

TAB 5b

GREENSTONE-MARATHON AREA INTEGRATED REGIONAL RESOURCE PLAN

Interim Report for the Near-Term (2015-2020)

Part of the Northwest Ontario Planning Region | June 22, 2015



Interim Integrated Regional Resource Plan

Greenstone-Marathon Area

As indicated in the Terms of Reference, this Interim Integrated Regional Resource Plan (“IRRP”) near-term report was prepared by the IESO on behalf of the Greenstone-Marathon Sub-region Working Group, which included the following members:

- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

The Greenstone-Marathon Sub-region Working Group assessed the adequacy of electricity supply to customers in the Northwest Region over a 5-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Northwest Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Greenstone-Marathon Sub-region Working Group members agree with the Interim IRRP’s near-term recommendations and support implementation of the plan through the recommended actions. Greenstone-Marathon Sub-region Working Group members do not commit to any capital expenditures. All necessary regulatory and other approvals to implement recommended actions must still be obtained by the appropriate parties.

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Appendix B: Studies to Establish Needs

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List of Abbreviations

Abbreviation	Description
ACSR	Aluminum Conductor, Steel Reinforced
AZA	Animbiigoo Zaagi'igan Anishinaabek
AEMO	Australian Energy Market Operator
BZA	Biinjitiwaabik Zaaging Anishinaabek
BNA	Bingwi Neyaashi Anishinaabek
CCRA	Capital Cost Recovery Agreement
CDM	Conservation Demand Management
C/I	Commercial and Industrial
CVNW	Common Voice Northwest Energy Task Force
CGS	Customer Generating Station
DG	Distributed Generation
DSC	Distribution System Code
ERCOT	Electric Reliability Council of Texas
EA	Environmental Assessment
EUE	Expected Unserved Energy
GS	Generating Station
Hydro One	Hydro One Networks Inc.
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
MVA	Mega Volt Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOMA	Northwestern Ontario Municipal Association

Abbreviation	Description
NPCC	Northeastern Power Coordinating Council
NPV	Net Present Value
NUG	Non-Utility Generator
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
OPG	Ontario Power Generation
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
Region	Northwest Ontario
SS	Switching Station
Sub-region	Greenstone-Marathon Area as a sub-region of the Northwest Region
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
SPS	Special Protection System
STATCOM	Static Synchronous Compensators
SVC	Static Var Compensators
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer
VCR	Value of Customer Reliability
VOLL	Value of Lost Load
WZI	Waaskinaysay Ziibi Inc.
WSFN	Whitesand First Nation
Working Group	Technical Working Group for Greenstone-Marathon Sub-region IRRP

1. Introduction

This Interim Integrated Regional Resource Plan (“IRRP”) for the Greenstone-Marathon Sub-region addresses the electricity needs for the sub-region over the near term (present-5 years). The report was prepared by the Independent Electricity System Operator (“IESO”) on behalf of the Technical Working Group for the Greenstone-Marathon Sub-region composed the IESO, Hydro One Distribution and Hydro One Transmission¹ (the “Working Group”).

The Greenstone-Marathon Sub-region includes the Red Rock Indian Band, Bingwi Neyaashi Anishinaabek (“BNA”), Biinjitiwaabik Zaaging Anishinaabek (“BZA”), Animbiigoo Zaagi’igan Anishinaabek (“AZA”), and the Long Lake #58, Ginoogaming, Aroland, Pays Plat, Ojibways of the Pic River and Pic Mobert First Nations. The area also encompasses the Town of Marathon, the Municipality of Greenstone, and the Townships of Nipigon, Manitouwadge, Schreiber, Terrace Bay and White River. The area covered by the Greenstone-Marathon Interim IRRP is a sub-region of the Northwest Region identified through the Ontario Energy Board (“OEB” or “Board”) regional planning process.

The regional planning process considers the local needs of a region over a 20-year planning horizon, and seeks to ensure cost-effective, reliable electricity supply to Ontario’s communities over the long term. An IRRP takes into consideration, among other things, the electricity requirements, anticipated growth, and existing electricity infrastructure in an area, and establishes a guide for electricity infrastructure investments, resource development, and procurement decisions for a region, and may include conservation, generation, transmission and/or distribution.

In early 2015, the Municipality of Greenstone and the electricity customers in the area advised the Working Group that the 18-month timeline for IRRPs established by the OEB could not satisfy the timeline of industrial developments anticipated in the area. Given that the forecast growth in the sub-region is driven by the potential for large industrial development, the municipality and the electricity customers requested that an interim planning report be developed to align with near-term development timelines. This interim report was prepared with the intent to facilitate critical decision making for customers in a manner that

¹ For the purpose of this report, “Hydro One Transmission” and “Hydro One Distribution” are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc., respectively.

accommodates near-term development timelines, considers electricity supply needs in the area, and ensures that the electricity system can support the pace of development.

Following the development of this Interim IRRP, a comprehensive 20-year IRRP will be produced in the first half of 2016.

- A summary of the recommended near-term plan for Greenstone-Marathon is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in Greenstone-Marathon and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and distributed generation (“DG”) assumptions are described in Section 5;
- Near-term needs in Greenstone-Marathon are presented in Section 6;
- Alternatives and recommendations for meeting near-term needs are addressed in Section 7;
- A summary of community, aboriginal and stakeholder engagement to date, and moving forward in developing the full IRRP, is provided in Section 8; and
- The recommended near-term plan is set out in Section 9.

Figure 1-1: Greenstone-Marathon Sub-region IRRP



2. The Integrated Regional Resource Plan

The Greenstone-Marathon Interim IRRP addresses the area's electricity needs over the next five years, based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The Interim IRRP uses a scenario-based analysis to identify requirements based on major industrial development for the near term (present-5 years). A full IRRP report will be developed in the first half of 2016 that will identify any further requirements in the medium term (5-10 years) and long term (10-20 years). These planning horizons are distinguished in the IRRP to reflect the different level of commitment required over these time horizons. The Greenstone-Marathon Interim IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility; and in the near term, it seeks to maximize the use of the existing electricity system, where it is economic to do so.

For the near term, the Interim IRRP identifies recommendations to assist customers and proponents in understanding the overall electricity needs of the area. The Interim IRRP identifies specific investments that respect development lead times that the Working Group recommends.

The medium and long term will be discussed in the full IRRP report. For the medium and long term, the IRRP will identify a number of alternatives to meet needs. However, as these needs are forecast to occur farther in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects. Instead, near-term actions will be identified to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. Actions identified for the near term will be directionally consistent with and inform the actions for the medium to long term.

The needs and recommended actions are summarized below.

2.1 Near-Term Plan Summary

The plan to meet the near-term needs of electricity customers in the Greenstone-Marathon Sub-region was developed considering planning criteria, including reliability, cost, feasibility, and maximizing the use of the existing electricity system where it is economic to do so. The near-term needs for the area consist of providing additional capacity to supply industrial development, while considering power quality and reliability requirements for the individual industrial developments.

The recommended elements of the near-term plan depend primarily on the outcome of two potential industrial customers: a mining development in Geraldton, and a major gas to oil pipeline conversion project. Therefore, a scenario-based planning approach has been taken in order to provide recommendations that address the different potential development scenarios that may develop in the area.

2.2 Recommended Actions

If forecast demand from distribution customers, the Geraldton mine, and the gas to oil pipeline conversion project materializes, the following are recommended (Stage 1 and Stage 2a):

Stage 1

- Install +40 MVar of reactive compensation at the Geraldton mine, to be in-service coincident with the first phase of the mine (2018).

Stage 2a

- Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac TS to be in-service coincident with the second phase of the Geraldton mine and pumping stations loads (2020).
- Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to be in-service coincident with the incorporation of the pumping stations as part of the major pipeline conversion project (2020).

Figure 2-1: Recommended Actions – Stage 1 and Stage 2a



If forecast demand from distribution customers and the Geraldton mine materialize but not the gas to oil pipeline conversion, the following are recommended (Stage 1 and Stage 2b):

Stage 1

- Install +40 MVar of reactive compensation at the Geraldton mine, to be in-service coincident with the first phase of the mine (2018).

Stage 2b

- Replace the existing sections of circuit A4L or the Geraldton mine developer may pursue on-site generation² in the order of a 2x10 MW gas generating facility, to be in-service coincident with the second phase of the Geraldton mine (2020).

² If the generation can operate in island-mode, it may be advantageous to pursue due to the inherent supply diversity that it offers in comparison to replacing circuit sections of A4L. The customer may also wish to investigate conservation incentives that the IESO offers to compliment this option.

Figure 2-2: Recommended Actions – Stage 1 and Stage 2b



If only forecast demand from distribution customers materialize, no new system enhancements are required.

The implementation of near-term plan elements require a capital cost agreement to be established between the future service provider and the new customers before development work can proceed.

2.3 Medium/Long-Term Plan Summary

The medium/long-term plan will be established in the full Greenstone-Marathon IRRP, scheduled for Q1 2016. Further engagement activities will take place prior to the finalization of the full Greenstone-Marathon IRRP.

3. Development of the IRRP

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as needed basis in Ontario for many years. Most recently, the Ontario Power Authority (“OPA”) carried out regional planning activities to address regional electricity supply needs. The OPA conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Board convened a Planning Process Working Group (“PPWG”) to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders, and in May 2013, the PPWG released its report to the Board³ (“PPWG Report”), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion was outlined. The Board endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code (“TSC”) and Distribution System Code (“DSC”) in August 2013, as well as through changes to the OPA’s licence in October 2013. The OPA’s licence changes required it to lead a number of aspects of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA’s licence were transferred to the IESO.

The regional planning process begins with a Needs Screening performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a

³ http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

comprehensive IRRP is required, which considers conservation, generation, transmission, and distribution solutions, or whether a straightforward “wires” solution is the only option such that a transmission and distribution focused Regional Infrastructure Plan (“RIP”) is required. The Scoping Assessment also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and so can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the Needs Screening process and a preliminary Terms of Reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. The transmitter may initiate and produce a RIP report for every region if necessary. A RIP may be initiated after the Scoping Assessment or after the completion of all IRRPs within a planning region. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO’s website for a 2-week comment period prior to finalization.

The final IRRPs and RIPs are posted on the IESO’s and relevant transmitter’s websites, and can be referenced and submitted to the Board as supporting evidence in a rate or “Leave to Construct” application for specific infrastructure investments. These documents are also useful for municipalities, First Nations communities and Métis community councils for planning, conservation and energy management purposes, for individual large customers that may be involved, and for other parties seeking an understanding of local electricity growth, conservation and demand management (“CDM”) and infrastructure requirements. Regional planning is not the only type of electricity planning that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system in Ontario:

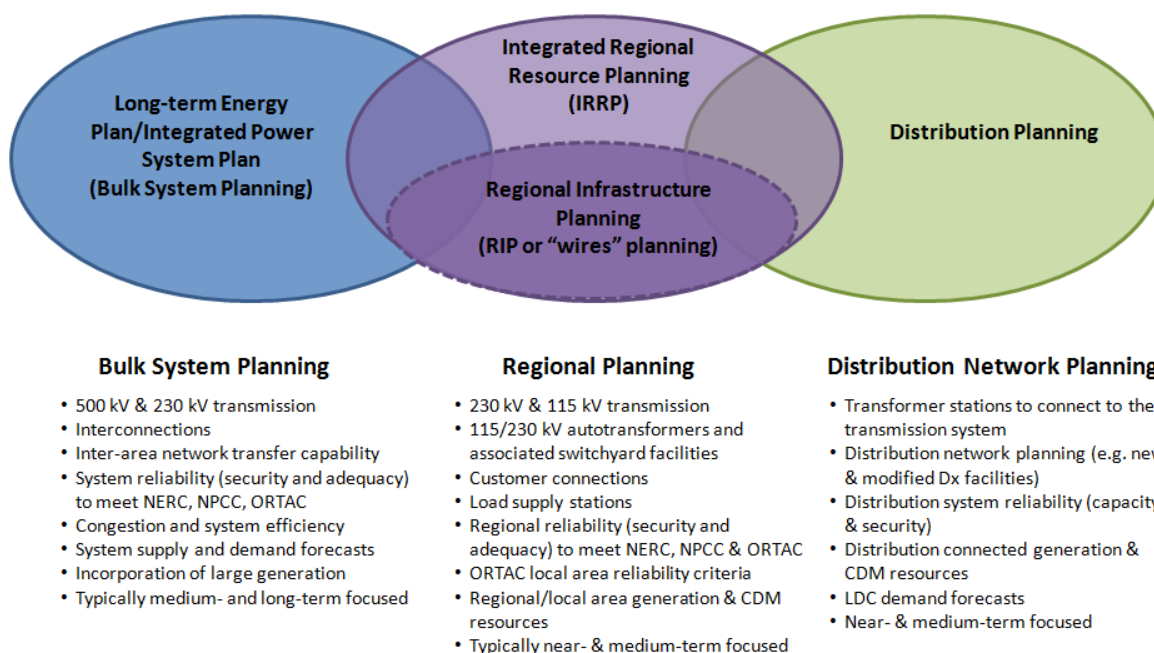
- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. Bulk system planning considers not only the major transmission facilities or “wires”, but it also assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government

policy. Distribution planning, which is carried out by Local Distribution Companies (“LDCs”), considers specific investments in an LDC’s territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, it is important for regional planning to be coordinated with both bulk and distribution system planning as it is the link between all levels of planning.

Figure 3-1: Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning, and coordinating multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region’s electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan in perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation,

generation, and “wires” solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public for feedback.

3.2 The IESO’s Approach to Integrated Regional Resource Planning

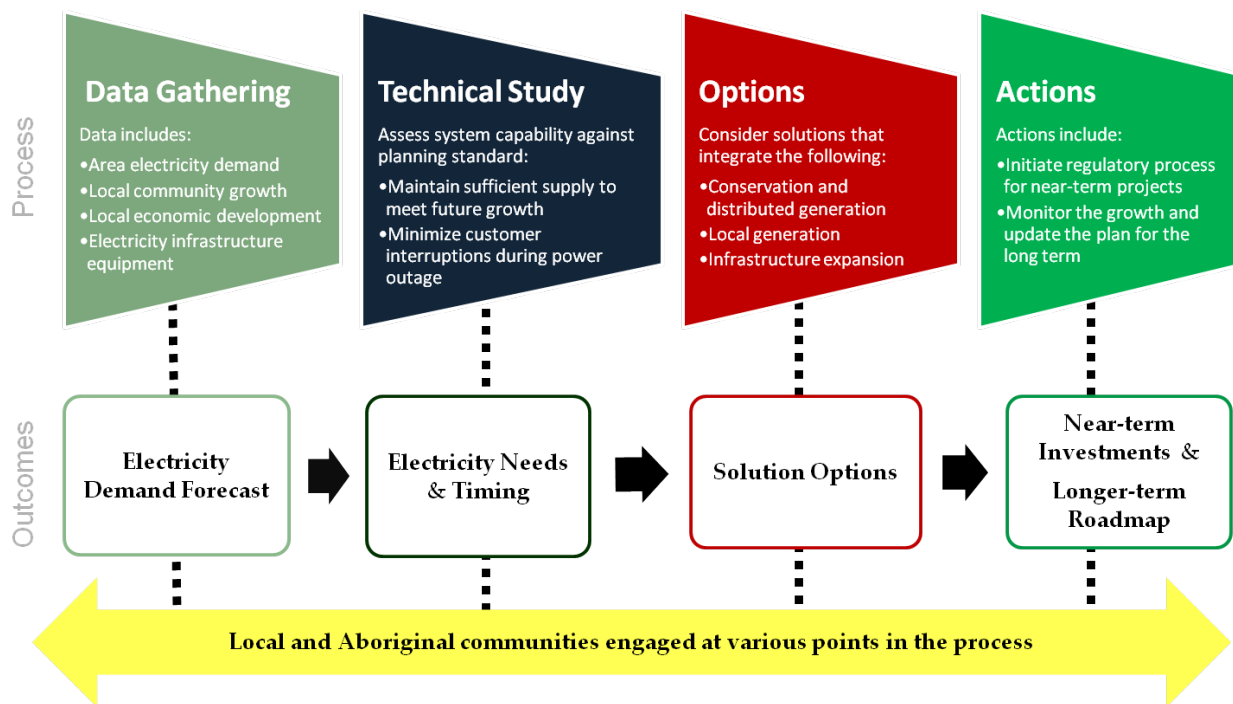
IRRP’s assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends in a region, so that near-term actions are developed within the context of a longer-term vision. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

Planning in northwestern Ontario requires a unique approach. In southern Ontario, most of the forecast load growth is driven by growth in the LDC customer base. In northwestern Ontario the majority of the forecast load growth is driven by new or expanding large transmission-connected industrial customers, the majority of which are in the resource sector or are unique development projects. Therefore, when establishing the need for electricity enhancements and developing integrated alternatives, industrial customers generally drive the nature and magnitude of the electrical demand requirements.

The near-term elements of the Interim IRRP represent the Working Group’s recommendations for system enhancements based on different scenarios. The Working Group recommends staging options to mitigate reliability and cost risks related to demand forecast uncertainty associated with individual large customers. The Interim IRRP considers the long-term IRRP elements qualitatively to ensure that the near-term recommendations can accommodate changing long-term conditions.

In developing this Interim IRRP, the Working Group followed a number of steps. These steps included: data gathering, including development of electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, preparation of a recommended plan including actions for the near and longer term. Throughout this process, engagement was carried out with municipalities, First Nation communities, Métis community councils and local stakeholders. These steps are illustrated in Figure 3-2 below.

Figure 3-2: Steps in the IRRP Process



The IRRP documents the inputs, findings, and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation.

3.3 Greenstone-Marathon Sub-region Working Group and IRRP Development

The Greenstone-Marathon Sub-region Working Group consists of representatives from the IESO, Hydro One Transmission, and Hydro One Distribution.

The IESO has also regularly met with transmission-connected load and generating customers in the area and the Interim IRRP was informed by these meetings. In particular, important information related to changes in electrical demand and generation production was provided by these customers.

3.4 Community, Aboriginal, and Stakeholder Engagement

Meaningful engagement with all communities in the Northwest was an important element in developing this interim report. Early engagement meetings were held in October 2014 and were attended by a broad range of stakeholders and First Nation and Métis community

members. In addition, the IESO attended meetings with municipalities, the Northwestern Ontario Municipal Association (“NOMA”), Common Voice Northwest (“CVNW”), and met with the board members of Waakiinaysay Ziibi Inc. (“WZI”) and a number of the Chiefs of the represented First Nations, and separately visited and met with Ojibways of Pic River First Nation and Pic Mobert First Nation. Greater detail regarding community, Aboriginal and stakeholder engagement activities is provided in Section 8 of this report.

4. Background and Study Scope

In 2014, the lead transmitter – Hydro One – initiated a Needs Screening process for the Northwest planning region. Planning initiatives for both the North of Dryden IRRP⁴ and Remote Community Connection Plan⁵ were already underway prior to the formalization of the regional planning process and were therefore not included within the scope of the Needs Screening process.

The Northwest Region Needs Screening study team determined that the need for coordinated regional planning had already been established and that a formal Needs Screening process was not required for the Northwest Region. The Needs Screening was then fast-tracked and a Scoping Assessment was initiated.

4.1 Study Scope

On December 12, 2014, a draft Scoping Assessment Outcome Report (“Scoping Report”) was posted for public comment. The Scoping Report⁶ was finalized on January 28, 2015 and it incorporated feedback from stakeholder and First Nation and Métis community meetings.

The Scoping Report identified three new planning sub-regions for coordinated regional planning: Thunder Bay, West of Thunder Bay, and Greenstone-Marathon.

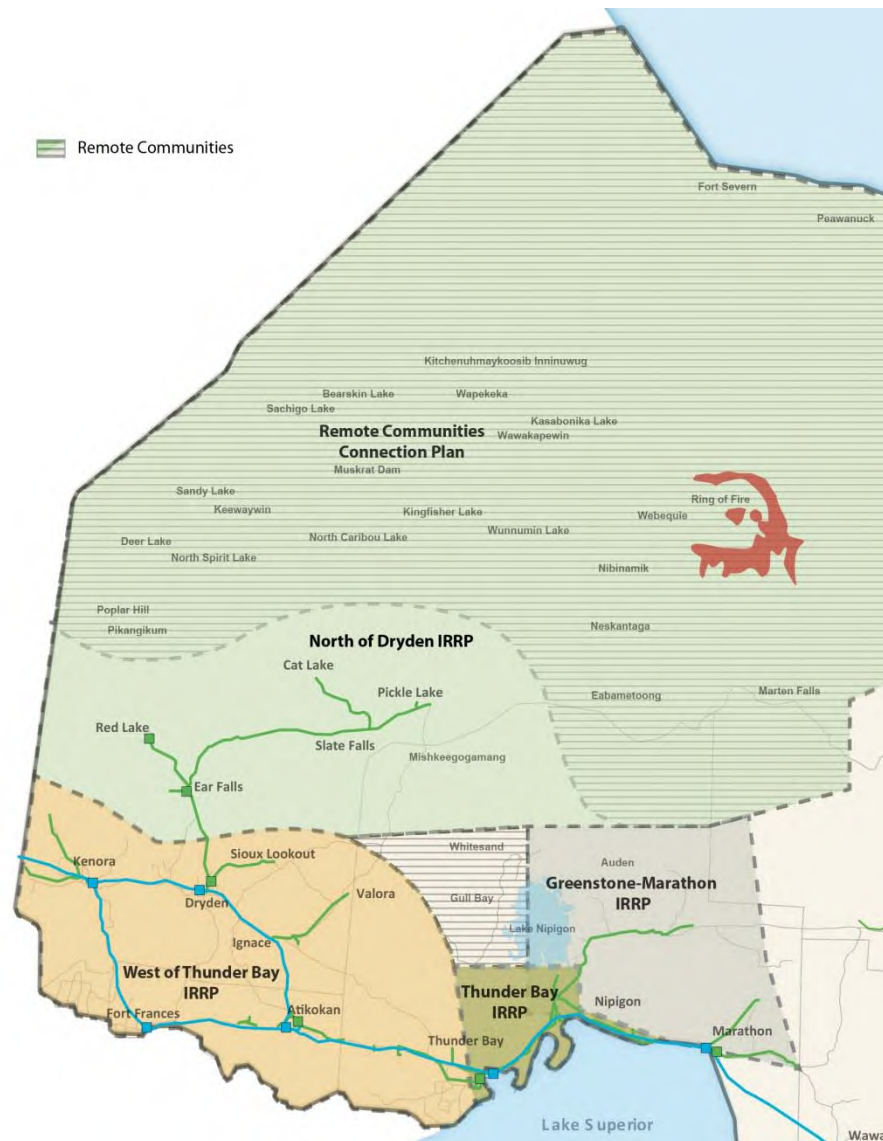
Regional planning initiatives in northwestern Ontario are illustrated in Figure 4-1.

⁴ <http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/North-of-Dryden.aspx>

⁵ <http://www.ieso.ca/Pages/Ontario%27s-Power-System/Regional-Planning/Northwest-Ontario/Remote-Community-Connection-Plan.aspx>

⁶ http://www.ieso.ca/Documents/Regional-Planning/Northwest_Ontario/Final%20Northwest%20Scoping%20Process%20Outcome%20Report.pdf

Figure 4-1: Northwest Planning Region and Sub-regions



4.2 The Greenstone-Marathon Area Electricity System

Electricity is supplied to the Greenstone-Marathon Sub-region from two main sources; Marathon TS and Alexander Switching Station (“SS”). Marathon TS is located in the Town of Marathon and is a 230/115 kV TS which is supplied at 230 kV from the East-West Tie. At Marathon TS, power is then transformed from 230 kV to 115 kV for transmission customers. Alexander SS is located outside of the Township of Nipigon and is a large switching station where a number of hydroelectric generators south of Lake Nipigon - Alexander Generating Station (“GS”), Cameron Falls GS, and Pine Portage GS - inject power into the system.

The Municipality of Greenstone and surrounding communities are supplied via a single-circuit 115 kV line (A4L) that connects from Alexander SS. Circuit A4L is approximately 150 km and generally follows the Highway 11 corridor. The natural gas-fired Nipigon GS, which holds a non-utility generator (“NUG”) contract, is also connected to A4L.

The Town of Marathon and surrounding area is supplied via a single-circuit 115 kV line (M2W) that originates at Marathon TS and branches north to Manitouwadge and east to White River. Circuit M2W has a total distance of approximately 200 km. Hydroelectric generation at Umbata Falls GS and Wawatay Customer Generating Station (“CGS”) also contributes to the electricity supply of the local area.

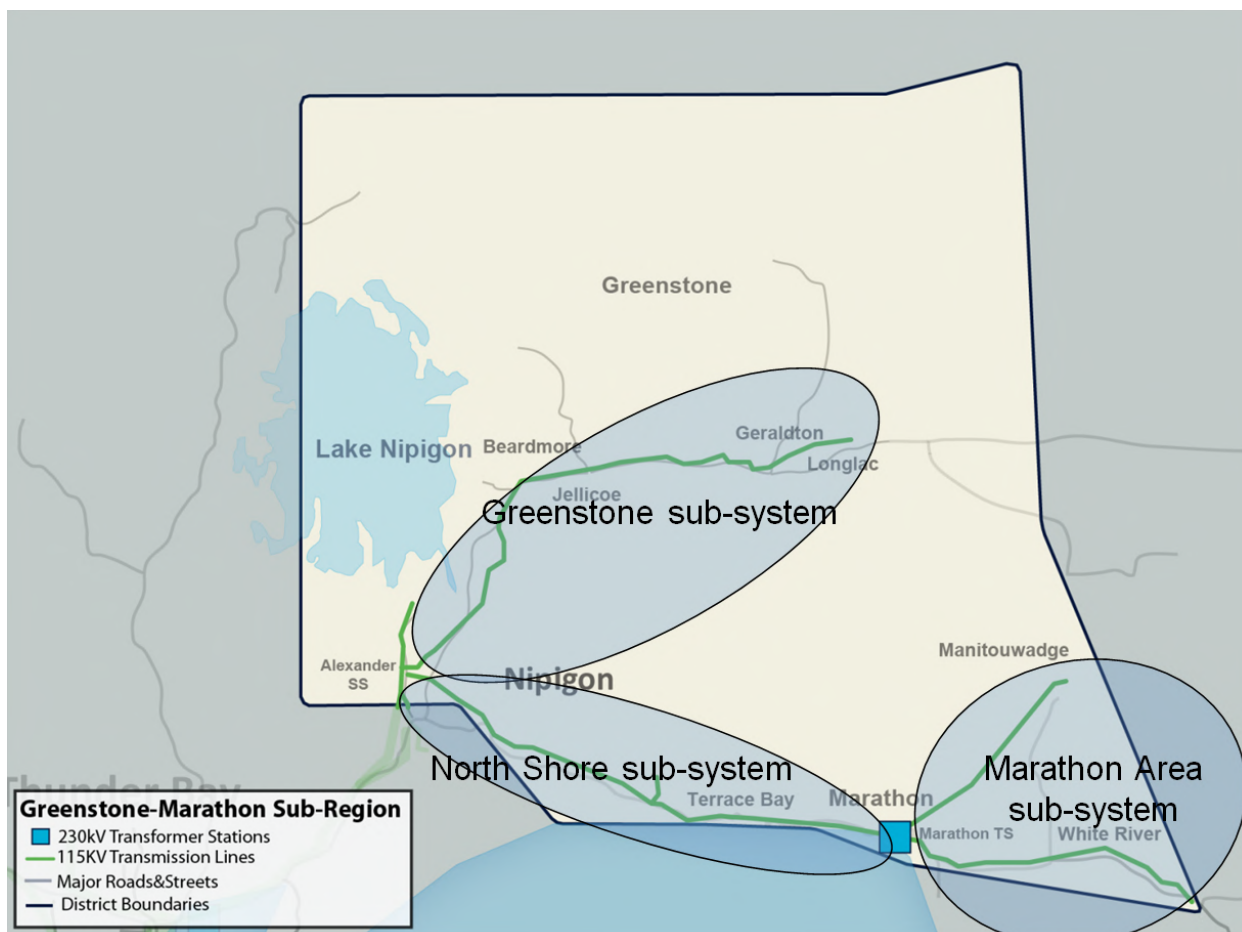
The communities along the north shore of Lake Superior, between Nipigon and Marathon are supplied from three circuits in series (A5A / A1B / T1M) that terminate at Marathon TS and Alexander SS. The three circuits generally follow the Highway 17 corridor and have a total distance of approximately 170 km. Hydroelectric generation at Aguasabon GS is connected at Aguasabon SS, which is the terminus for circuits A5A and A1B, and also contributes to the supply of the local area.

4.3 Greenstone-Marathon Area Sub-systems

Within the Greenstone-Marathon area, there are three electrical sub-systems: Greenstone, North Shore, and Marathon.

The facilities supplying each sub-system are illustrated in Figure 4-2.

Figure 4-2: Study Scope and Sub-systems



4.3.1 Greenstone Sub-system

The Greenstone sub-system is defined as the existing and potential customers serviced from circuit A4L from Alexander SS to Longlac TS. Circuit A4L generally follows Highway 11 from Nipigon to Longlac. Circuit A4L serves the communities comprising the Municipality of Greenstone and serves as connection for Nipigon GS.

4.3.2 North Shore Sub-system

The North Shore sub-system is defined as the existing and potential customers serviced from circuits A5A, A1B, and T1M, from Alexander SS to Marathon TS. Circuits A5A, A1B, and T1M are in series and generally follow the Highway 17 corridor. Together, these circuits interconnect Alexander SS to Marathon TS, however, each circuit comprises its own protection zone such that a fault on any of the three circuits will not interrupt supply on the other two. Hydroelectric

generation at Aguasabon GS is connected to the system at Aguasabon SS which is the interconnection between A5A and A1B.

4.3.3 Marathon Area Sub-system

The Marathon area sub-system is defined as the existing and potential customers serviced from circuit M2W, radial from Marathon TS to Manitouwadge TS and White River DS. Hydroelectric generation at Umbata Falls GS and Wawatay CGS is also connected to the system by circuit M2W.

5. Demand Forecast

5.1 Methodology for Establishing a Planning Forecast

The first step in developing an IRRP is establishing a planning forecast. A planning forecast is developed from a compilation of electrical demand data collected from LDCs and potential large customers connected directly to the transmission system. The effects of weather and coincidence factors are considered. Also, the demand reduction from CDM and DG are accounted for when developing the net demand forecast.

As part of the lead transmitter's Needs Screening, LDCs are required to submit 10-year gross station demand forecasts. Consistent with the PPWG Report, LDC demand forecasts are further refined and a long-term (10-20 years) projection is also produced. Hydro One Distribution is the sole distributor in the Greenstone-Marathon Sub-region and it provided the Working Group with the gross station demand forecast and related assumptions.

The effects of DG and expected conservation from LDC conservation targets were then accounted for, establishing the net station demand forecasts.

The IESO regularly communicates with existing and potential transmission-connected industrial customers to ensure there is an understanding of their future electricity demand. In the Greenstone-Marathon Sub-region, new industrial customers account for the majority of the forecast demand growth. However, the magnitude and timing of the electrical demand growth associated with large industrial customers, especially those in the natural resource sector (e.g., mining, oil, forestry) depend on a number of external factors such as the commodity price of the resource, the economic viability, and the ability to secure capital. In order to account for uncertainty of natural resource-based customers, the IESO developed multiple demand scenarios for potential transmission-connected industrial customers by considering a number of factors, including:

- Customer plans
- Stage of development (e.g., under construction, undergoing an Environmental Assessment ("EA"), still in exploration, etc.)
- Financial feasibility (e.g., results of publically available economic assessments)
- Potential environmental impacts
- Existing infrastructure and accessibility
- Global markets (e.g., commodity prices, customers and demand)

Net planning forecasts were developed based on LDC gross station demand forecast, the impact of CDM and DG, and the forecast scenarios of transmission-connected industrial customers.

5.2 Forecast Elements

The forecast developed for the Greenstone-Marathon Interim IRRP includes quantitative and qualitative contributions from a number of parties including Hydro One Distribution, individual existing and potential industrial customers, local municipalities, First Nation communities and Métis community councils, industry associations, and interest groups.

5.2.1 Local Distribution Company Gross Demand Forecast

To support the regional planning process, the DSC requires that the LDCs provide gross station demand forecasts representing distribution customer demand projections. Hydro One Distribution has provided gross forecast projections for the step-down supply stations within the Greenstone-Marathon Sub-region indicated in Table 5-1 below.

Table 5-1: Step-down Stations by Sub-system

Greenstone Sub-system	North Shore Sub-system	Marathon Area Sub-system
Beardmore DS #2	Marathon DS	Manitouwadge DS #1
Jellicoe DS #3	Schreiber Winnipeg DS	Manitouwadge TS
Longlac TS		Pic DS
		White River DS

LDC forecasts also include small industrial customers, such as saw mills, connected to the distribution system. One notable inclusion is the re-start of two saw mills in the Greenstone area.

5.2.2 Conservation Assumed in the Forecast

In developing planning forecast scenarios, the Working Group also considered the extent to which planned CDM may impact peak demand.

In the report “Achieving Balance: Ontario’s Long-Term Energy Plan” (“2013 LTEP”), the Ontario government established a provincial CDM target of 30 TWh in electricity reduction by 2032. To assist in achieving this target, the 2013 LTEP also committed to establishing a new 6-year Conservation First Framework beginning in January 2015. In order to represent the

effect of provincial conservation targets within regional planning, the IESO developed an annual forecast for peak demand savings based on the provincial energy savings target which it expressed as a percentage of demand in each year. These percentages were applied to the LDC demand forecast to develop an estimate of the peak demand impacts from the provincial targets in the Greenstone-Marathon Sub-region. The CDM targets included in developing the net demand forecast are provided in Table 5-2 below.

Table 5-2: Conservation Targets by Sub-system

Sub-system	Peak Reduction due to Conservation [MW]				
	2015	2020	2025	2030	2035
Greenstone	0.1	0.4	1.4	2.2	2.5
North Shore	0.1	0.6	1.2	2.0	2.3
Marathon Area	0.2	1.0	1.9	3.0	3.5

5.2.3 Transmission Connected Customer Demand Forecast

The majority of forecast demand growth in the Greenstone-Marathon Sub-region is anticipated to be driven by potential large industrial customers that may connect directly to the transmission system. These potential industrial projects include a gold mine near Geraldton, a precious metals mine near Marathon, and a portion of a large gas to oil pipeline conversion project that generally follows the Highway 11 corridor.

As the mandate of the Working Group only covers electricity planning, the Working Group considers these potential industrial developments only in the context of electricity demand requirements for the sub-region.

5.3 Planning Forecast

To address peak electricity demand requirements for the sub-region, a scenario-based planning approach was used to account for uncertainty in producing a demand forecast for the area. As a result, the Greenstone-Marathon planning forecast consists of three scenarios – A, B, and C – which account for different possible industrial development outcomes. The Working Group does not consider any of these scenarios more or less likely to occur. The scenarios all represent plausible outcomes that must be considered in planning for the electricity needs of the sub-region.

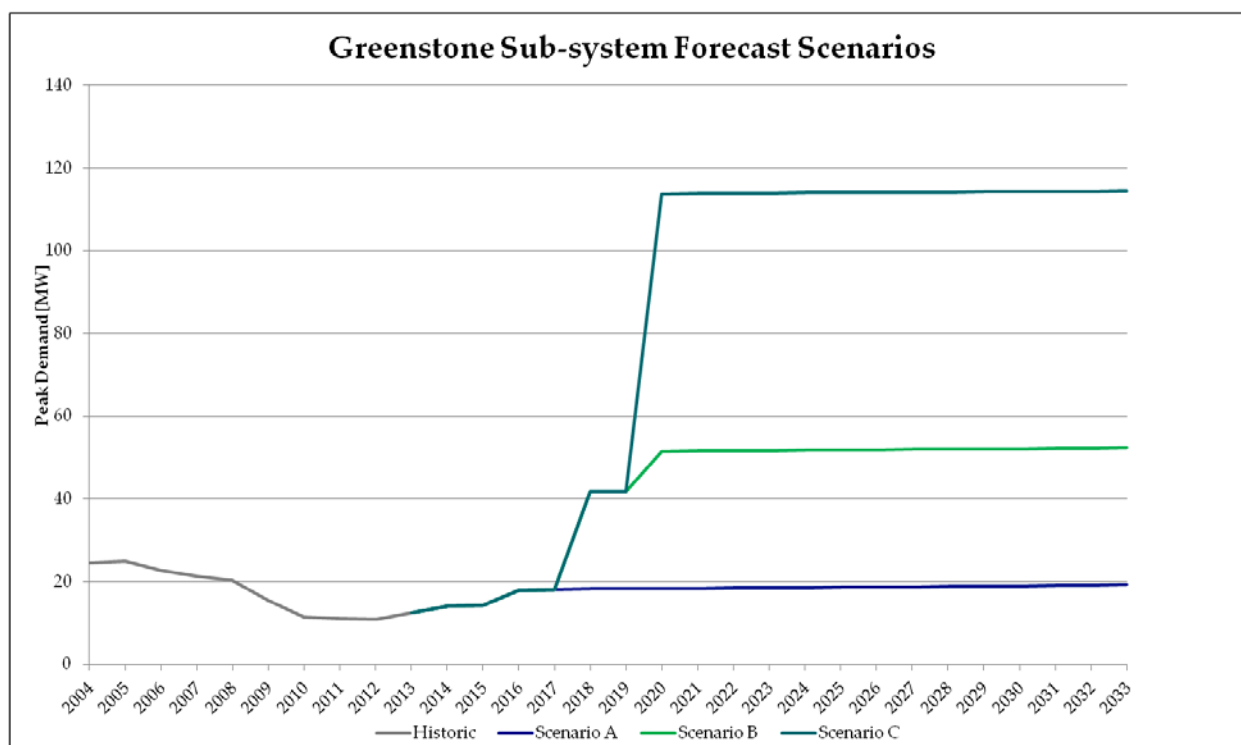
5.3.1 Greenstone Sub-system Forecast Scenarios

The following summarizes the forecast scenarios considered for the Greenstone sub-system.

Table 5-3: Greenstone Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth (including two saw mill re-starts)
B	Hydro One Distribution customer growth (including two saw mill re-starts), and Geraldton mine materializes
C	Hydro One Distribution customer growth (including two saw mill re-starts), Geraldton mine materializes, and gas to oil pipeline conversion project materializes

Figure 5-1: Greenstone Sub-system Forecast Scenarios



It should be noted that the Greenstone sub-system forecast Scenarios B and C are equivalent until 2020, at which point they diverge. This is important when considering staging of options and will be discussed further in Section 7.2.2.

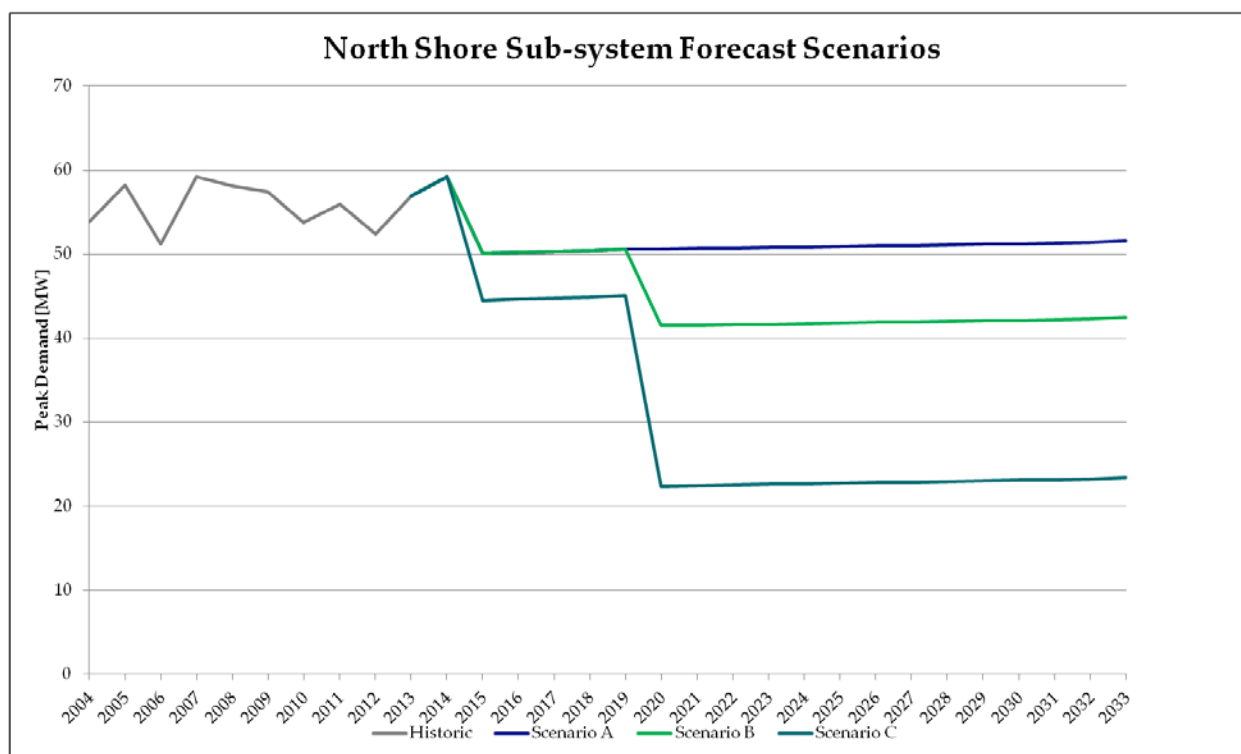
5.3.2 North Shore Sub-system Forecast Scenarios

The following summarizes the forecast scenarios considered for the North Shore sub-system.

Table 5-4: North Shore Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth, industrial customer behind-the-meter generation ⁷ (low generation)
B	Hydro One Distribution customer growth, industrial customer behind-the-meter generation (mid generation)
C	Hydro One Distribution customer growth, industrial customer behind-the-meter generation (high generation)

Figure 5-2: North Shore Sub-system Forecast Scenarios



⁷ Behind-the-meter generation is generation that is located on the customer’s side of the meter that measures demand from the grid.

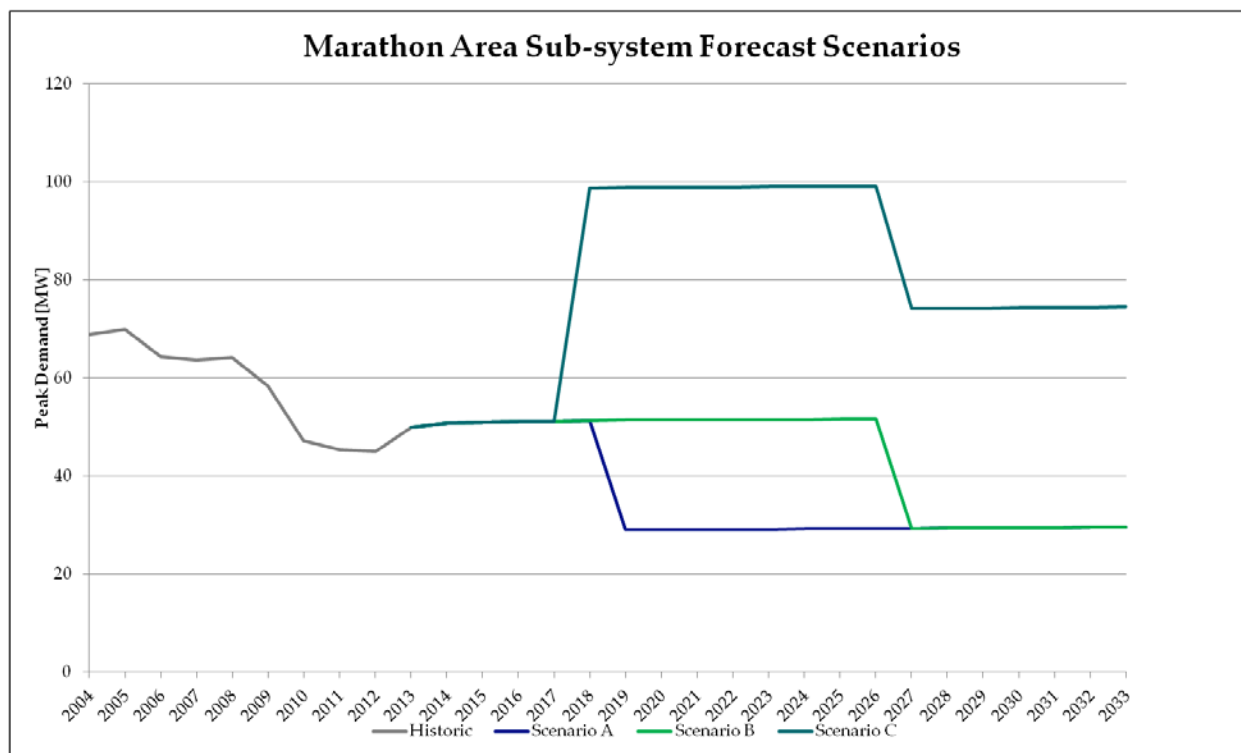
5.3.3 Marathon Area Sub-system Forecast Scenarios

The following summarizes the forecast scenarios considered for the North Shore sub-system.

Table 5-5: Marathon Area Sub-system Forecast Scenarios

Scenario	Description
A	Hydro One Distribution customer growth, no extension of existing Marathon area mine life
B	Hydro One Distribution customer growth, with extension of existing Marathon area mine life
C	Hydro One Distribution customer growth, with extension of existing Marathon area mine life, and new Marathon area precious metals mine materializes

Figure 5-3: Marathon Area Sub-system Forecast Scenarios



6. Electricity System Needs

For the purpose of this Interim IRRP, the following section details the near-term needs (present-5 years) established by the Working Group. The medium and long-term needs will be assessed in the final IRRP report.

6.1 Methodology for Establishing Power System Needs

Once the planning forecast is developed, power system needs are established by determining the load meeting capability (“LMC”) of the power system and determining if a shortfall exists between the electricity that can be supplied by the system in comparison to the forecast demand.

In order to determine the LMC of the power system supplying the Greenstone-Marathon Sub-region, the ORTAC, the Northeastern Power Coordinating Council (“NPCC”) Directory #1 Standards, and the North American Electric Reliability Corporation (“NERC”) Transmission Planning Standards (“TPL-001-4”) are applied. These documents outline power system planning and design standards and all are publically available.⁸

ORTAC represents the compilation of standards and best-practices in Ontario for long-term electricity plans, including IRRPs. ORTAC identifies certain system conditions, including contingencies, and the required level of performance under those conditions. The performance of the system is categorized based on equipment loading, voltage performance, load security and restoration (acceptable time periods for restoring customers after specified contingencies). Appendix A details the criteria applied in this Interim IRRP.

6.2 Existing System Load Meeting Capability

In order to establish electricity supply requirements for the Greenstone-Marathon Sub-region, it is necessary to determine the LMC of each of the Greenstone, North Shore and Marathon area sub-systems. The LMC of each sub-system is largely dependent on the connection point of the new customers indicated previously. This is especially true in northwestern Ontario where the LMC of long circuits may be limited by voltage.

⁸ ORTAC: http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

NPCC Directory #1:

https://www.npcc.org/Standards/Directories/Directory%201_Design%20Ops%20BPS%20clean%20GJD%2020150331_GJD.pdf

NERC TPL-001-4: <http://www.nerc.com/files/TPL-001-4.pdf>

6.2.1 Greenstone Sub-system Load Meeting Capability

The Greenstone sub-system is limited by voltage for new customers near the Longlac area. The existing system, consisting of the A4L transmission line, has a total LMC of approximately 25 MW assuming the majority of load is concentrated in the Geraldton and Longlac areas near the end of the circuit. Based on demand forecast Scenario A, the Greenstone sub-system is not expected to be limiting, however Scenarios B and C are forecast to exceed the 25 MW limit. It should be noted that although circuit A4L is limited by voltage, it has a summer thermal rating of 260 A, or approximately 45 MW.⁹

6.2.2 North Shore Sub-system Load Meeting Capability

In addition to supplying customers, the North Shore sub-system also serves as the bulk system underlay for the East-West Tie. The North Shore sub-system can accommodate a total of approximately 100 MW of load and through-flow (from bulk transfers) during normal conditions. Flow along the North Shore sub-system is not expected to exceed 100 MW during normal conditions, even when the East-West Tie is loaded to its fair weather transfer limit and under a variety of local hydroelectric conditions.

Under the post-contingency condition where the double-circuit line M23L/M24L (which is a portion of the East-West Tie) between Marathon to Lakehead is lost, flows may exceed 100 MW along the North Shore sub-system during high transfer conditions. Overloading is mitigated and reliability is maintained by ensuring load is continuously supplied pre-contingency by the availability of the Northwest Special Protection System (“SPS”). Following the reinforcement of the East-West Tie between Wawa TS and Lakehead TS, currently planned to be in-service for 2020, reliability to the Northwest will be improved and the North Shore sub-system will also be able to accommodate further growth. The North Shore sub-system is not expected to be limiting for new customers during this planning cycle.

6.2.3 Marathon Area Sub-system Load Meeting Capability

The Marathon area sub-system is limited by voltage performance. Incremental reactive compensation would be required to connect additional customers. The further customers are from Marathon TS, the more reactive compensation would be required. The maximum load

⁹ In order to release the full thermal capability of facilities that are limited by voltage, reactive compensation of sufficient amounts to address the voltage limit would need to be installed. This is considered further in the Alternatives section of the report.

that the Marathon area sub-system can accommodate based on the ORTAC load security limit for a single-circuit line is 150 MW.

Based on existing forecasts, the Marathon area sub-system is not expected to be limiting for new customers during this planning cycle.

6.3 Near-Term Needs

The near-term needs are described below by sub-system for each planning forecast scenario.

6.3.1 Near-Term Needs: Greenstone Sub-system

Capacity

The near-term capacity needs have been determined by comparing the near-term demand forecast to the LMC of the sub-system, and are tabulated below:

Table 6-1: Summary of Near-Term (present-5 years) Capacity Needs for the Greenstone Sub-system

Demand Forecast [MW]	2015	2016	2017	2018	2019	2020
Scenario A	14	18	18	18	18	18
Scenario B	14	18	18	42	42	51
Scenario C	14	18	18	42	42	114
Greenstone LMC¹⁰ [MW]	25					
Capacity Need [MW]						
Scenario A	0	0	0	0	0	0
Scenario B	0	0	0	17	17	26
Scenario C	0	0	0	17	17	89

Power flow studies are included in Appendix B.

Load Security and Restoration

All demand forecast scenarios being considered up to 2020 remain less than 150 MW. This complies with the load security criteria outlined in ORTAC for a single-circuit line, which

¹⁰ Based on the capability of circuit A4L without any additional reactive compensation.

requires that no more than 150 MW be lost due to an outage on that line. Also restoration from a normal outage should remain under 8-hours, consistent with ORTAC.

Restoration from forced outages has generally performed within ORTAC. In the last five years, forced outages have been restored within eight hours with the exception of two sustained outages. These outages occurred during the evening and overnight. The spirit of the 8-hour criterion is that all non-catastrophic forced outages can be restored within a working day. Provisions exist in ORTAC to account for outages that take place outside of normal working hours and away from staffed centres; “approximate restoration times are intended for locations that are near staffed centres... [and] restoration times should be commensurate with travel times and accessibility”¹¹ (ORTAC 7.2). Therefore, no load security or restoration needs have been identified in the near term. A comprehensive reliability analysis is included in Appendix E.

Additional Customer Requirements

Fault analysis indicates that the available short-circuit at the end of circuit A4L is about 140 MVA¹² at the Longlac TS 115 kV bus. A potential mining customer near Geraldton has indicated that it requires at least 150 MVA available short circuit at 13.8 kV supply to ensure the functioning of its equipment. It has been estimated that the available short circuit would be about 105 MVA at 13.8 kV at the proposed Geraldton mine. This indicates that solutions for the area must increase the available short circuit level, through the use of generators, synchronous condensers or static synchronous compensators (“STATCOM”) for scenarios that consider the Geraldton mine. Passive devices such as capacitors or Static Var Compensators (“SVCs”) cannot provide the required short circuit level.

For forecast scenarios that include the large oil pipeline conversion project, it has been noted that adjacent pumping stations cannot be lost for the same contingency. Therefore, provisions for appropriate supply diversity must be included for these relevant scenarios.

6.3.2 Near-Term Needs: North Shore Sub-system

The existing electrical system supplying the North Shore sub-system is expected to be sufficient for the planning horizon. As indicated in Section 5.3, the North Shore sub-system is not forecast

¹¹ ORTAC: http://www.ieso.ca/documents/marketAdmin/IMO_REQ_0041_TransmissionAssessmentCriteria.pdf

¹² Assuming the outage of Nipigon GS, representing a scenario that short-circuit availability is low

to experience net demand growth. It is expected that the installation of customer generation may reduce the forecast peak demand in the long-term. Power flow study results are included in Appendix B for reference, and indicate that facilities are expected to perform within ratings with sufficient reliability.

6.3.3 Near-Term Needs: Marathon Area Sub-system

The existing electrical system supplying the Marathon area sub-system is expected to be sufficient for the near-term planning horizon considered for this planning cycle.

This is also supported by the Stillwater Canada Inc. System Impact Assessment (“SIA”) Report for the Marathon PGM (Platinum Metals Group) Copper Project, available on the IESO website.¹³

Power flow study results are included in Appendix B, and indicate that facilities are expected to perform within ratings with sufficient reliability.

6.4 Medium-Term Needs

(This section is intentionally left blank. To be developed in Final 20-year IRRP report)

6.5 Long-Term Needs

(This section is intentionally left blank. To be developed in Final 20-year IRRP report)

¹³ http://www.ieso.ca/Documents/caa/CAA_2012-476_Final_Report.pdf

7. Alternatives for Meeting Near-Term Needs

7.1 Methodology for Alternatives Development and Comparison

Once needs are identified, alternatives are developed that are technically feasible and are then compared on a relative basis against criteria such as cost, reliability, environmental impact, and social acceptance. If a decision is required, given the forecast timing of needs and lead times for implementing feasible alternatives, a recommendation is made.

Alternatives may consist of one or a combination of CDM, generation, transmission, and/or distribution. Integrated alternatives that are capable of satisfying criteria for the forecast system condition and for the applicable scenario being assessed are then considered. Alternatives that are not capable of satisfying criteria are screened out and not considered further.

An economic analysis of the technically feasible alternatives is performed and the net present value (“NPV”) of each option is determined based on the amortized costs that are incurred within a 20-year planning horizon.¹⁴ Generation and conservation options that contribute to provincial system supply needs are appropriately credited with the related economic benefit to ensure consistent comparison with all other options. Other factors such as environmental impact and social acceptance are considered, including information obtained from the engagement process. Detailed environmental impact analysis is performed at the time the project reaches the Environmental Assessment.

7.2 Alternatives Considered

7.2.1 Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Conservation is achieved through a mix of program-related activities including behavioral changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

However within the Greenstone-Marathon Sub-region, the majority of the forecast load growth is anticipated to result from new industrial development, which is assumed to include relatively efficient equipment given the inherent economic benefits and improved codes and standards.

¹⁴ This is not the total project cost.

Conservation expected to be achieved through provincial targets has already been included in the net demand forecast. Therefore the potential for significant conservation that could address needs is limited.

One of the available programs that transmission-connected customers could be eligible for is the Industrial Accelerator program (“IAP”). The IAP is geared to reducing electricity consumption on the provincial system, and to helping companies become more competitive by providing financial incentives that encourage investment in innovative process changes and equipment retrofits. Opportunities for energy savings through the IAP will continue to be explored for new and existing transmission-connected customers in the Greenstone-Marathon Sub-region.

7.2.2 Greenstone Sub-system Alternatives

The following sections describe the analysis of the different alternatives considered for each of the Greenstone sub-system forecast scenarios.

As indicated earlier, the Greenstone sub-system consists of one single-circuit 115 kV transmission line (A4L) with limited capacity and the near-term need for new capacity is driven by two specific industrial developments. Given the options must account for a number of factors such as the limitations of the existing system, the identified needs, and the staging of industrial customer electrical demand increases, a single transmission, generation, or DG alternative will not fulfill the range of customer requirements. In order to develop options that provide for the full scope of existing system limitations and customer capacity requirements, combinations of transmission, large generation, and DG facilities are considered. Off-grid alternatives are also considered for the purpose of cost comparisons. These alternatives include the following scenarios:

Table 7-1: Summary of Alternatives Considered for Scenarios

Scenario	Alternative
A	"A0" – Continued sustainment of existing transmission system
B	"B1" – Install reactive compensation and distributed generation
	"B2" – Install off-grid generation
	"B3" – Install reactive compensation and replace sections of circuit A4L
C	"C1" – Install reactive compensation, new 230 kV transmission supply and off-grid generation
	"C2" – Install reactive compensation, new 230 kV transmission supply and 115 kV connection line
	"C3" – Install new grid-connected gas generation and 115 kV connection line
	"C4" – Install off-grid generation

The result of the scenario-based alternative analysis is summarized below.

Scenario A does not result in the need for any new facilities.

Analysis of Scenarios B and C indicates that a staged approach for recommended capacity enhancements is best to align with the timing of industrial developments. As indicated in Section 5.3.1, Scenarios B and C are equivalent until 2020, and therefore the recommended Stage 1 is common to both scenarios to address capacity needs up to 2020.

Recommended Stage 1 (up to 2020)
<ul style="list-style-type: none"> • Install +40 MVar of reactive compensation in the form of either a synchronous condenser or STATCOM at the Geraldton mine, to be in-service coincident with the first phase of the mine – 2018

In 2020, Scenarios B and C diverge. Scenario B includes the incremental demand from the second phase of the Geraldton mine, whereas Scenario C includes both the incremental mining demand and the demand from the gas to oil pipeline conversion project. Therefore Stage 2 has two options depending on whether the gas to oil pipeline conversion project materializes.

If, in addition to the Geraldton mine, the gas to oil pipeline conversion project proceeds and commits to electricity service according to schedule (2020), and consistent with Scenario C, the recommendation is:

Recommended Stage 2a (2020 and onward)

- Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac TS to be in-service coincident with the second phase of the Geraldton mine and pumping stations loads – **2020**
- Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to be in-service coincident with the pumping station loads – **2020**

If the second phase of the Geraldton mine proceeds (2020), but the gas to oil pipeline conversion project does not proceed or does not commit to grid supply, consistent with Scenario B, the recommendation is:

Recommended Stage 2b (2020 and onward)

- Replace the existing sections of circuit A4L, or the Geraldton mine developer may pursue on-site generation¹⁵ on the order of a 2x10 MW gas generating facility, to be in-service coincident with the second phase of the Geraldton mine – **2020**

The following sections provide a detailed analysis of the alternatives listed in Table 7-1.

7.2.2.1 Continued Sustainment of Existing System (“Option A0”)

Under forecast Scenario A, no new industrial customers are supplied from the transmission grid. Under this scenario, the existing transmission system is sufficient to meet electrical capacity requirements in the Greenstone sub-system. No new facilities are required.

A comprehensive reliability analysis is included in Appendix E.

To maintain the reliability of circuit A4L, continued routine maintenance and sustainment activities consistent with Hydro One’s maintenance practices and sustainment plans are expected to be adequate and meet planning criteria.

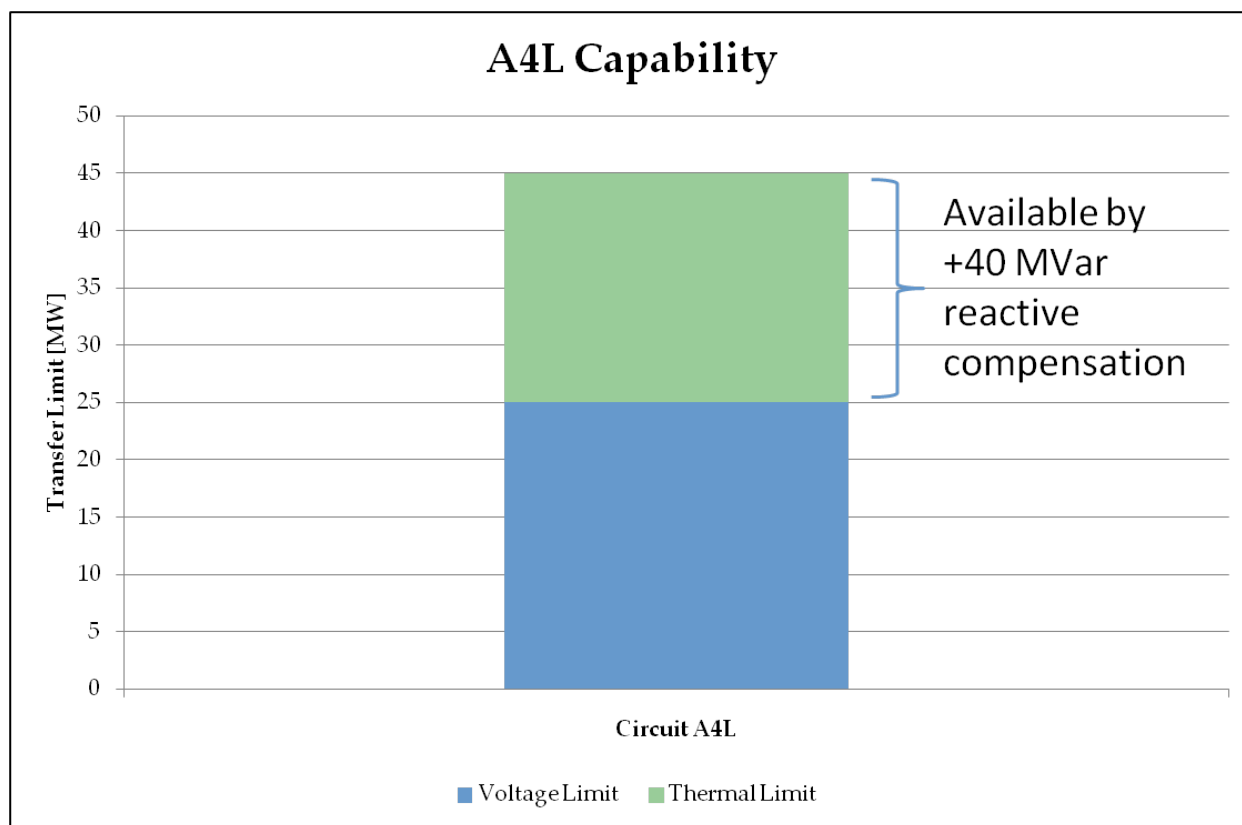
7.2.2.2 Install Reactive Compensation and Distributed Generation (“Option B1”)

This option considers the needs based on load forecast Scenario B.

¹⁵ If the generation can operate in island-mode, it may be advantageous to pursue this option due to the inherent supply diversity that it offers in comparison to replacing circuit sections of A4L. The customer may also wish to investigate conservation incentives that the IESO offers, such as the IAP, to compliment this option.

This alternative consists of installing additional reactive compensation of approximately +40 MVar in the form of either a synchronous condenser or STATCOM.¹⁶ This would release the full thermal capability of the circuit of 260 A, or approximately 45 MW (i.e. incremental LMC of 20 MW). As indicated in Section 6.3.1, considering motor starting requirements of the Geraldton mine, reactive compensation solutions would need to increase short circuit levels to 150 MVA at the mine site. Devices such as synchronous condensers or STATCOMs would be able to increase the available short circuit level, but passive devices such as capacitor banks or SVCs would not. This has been considered in the economic analysis by assuming the planning level capital cost estimate of the reactive compensation consistent with that of a synchronous condenser, which is approximately \$7.5 million (or \$5 M NPV).¹⁷ It should be noted that STATCOMs are expected to be comparable in cost.

Figure 7-1: Increase in A4L Capability with +40 MVar of Reactive Compensation



¹⁶ In order to accommodate planned and unplanned outages, a SPS is also recommended.

¹⁷ Estimate provided by Hydro One from ABB.

Based on customer information provided to the IESO and indicated in the forecast, this is expected to be sufficient to accommodate the first phase of the Geraldton mine (to 2019) and expected LDC demand growth until 2020.

In order to accommodate the expected 10 MW incremental capacity deficiency associated with the second phase of the Geraldton mine in 2020, two 10 MW (or three 5 MW) gas-fired generators may be installed. For costing purposes, these generators are expected to produce about 43 GWh per year, which corresponds to the electricity that the mine is expected to require in excess of the 25 MW of capacity that may be grid-supplied.

A major benefit of using a combination of grid supply and local generation compared to Options B2 and B3 is the supply diversity. A contingency involving the grid or the on-site generators would still allow the mine to continue some degree of production.¹⁸ The customer may also wish to investigate conservation incentives that the IESO offers, such as the IAP, to compliment this option and further reduce their costs.

Power flow study results are included in Appendix C, and indicate that facilities are expected to perform within ratings with sufficient reliability.

The related economic analysis is included in Appendix D for reference.

The details of Option B1 are summarized below:

Table 7-2: Summary of Option B1

Option B1¹⁹	
Incremental Utilized Capacity [MW]	26
Net Present Value Cost [M\$]	55
Net Present Value Cost per Utilized Capacity [M\$/MW]	2.1
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

¹⁸ The level of supply security described for Option B1 would require that provisions are made such that the on-site generators being described can operate in island mode.

¹⁹ Using cost estimates for 9.5 MW gas engines as a representative cost.

7.2.2.3 Install Off-Grid Generation (“Option B2”)

This option considers the needs based on load forecast Scenario B.

Circuit A4L, which serves the Greenstone sub-system, runs parallel to a portion of the TransCanada natural gas pipeline. A possible option is to continue to serve LDC demand with the existing electricity infrastructure, and for the Geraldton mine to supply their entire facility with on-site natural gas generation (i.e. not interconnected with the IESO-controlled grid). This option is included to provide existing and future customers with the full range of available options. It should be noted that the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid.²⁰

The publically available draft EA Terms of Reference²¹ for the Premier Gold Mines Ltd. Hardrock Mine indicates that 56 MW of generation capacity is anticipated to be required to meet demand with necessary redundancy.

For the purpose of the economic comparison, the installation of a 6x9.5 MW gas-fired engine power plant is assumed. This arrangement would provide the required capacity indicated and account for N-2 redundancy. The on-site generation would produce approximately 185 GWh per year once phase 1 of the mine is complete and approximately 260 GWh per year once phase 2 is complete.

The related economic analysis is included in Appendix D.

The details of the option are summarized below.

Table 7-3: Summary of Option B2

Option B2	
Installed Capacity [MW]	57 (6x9.5)
Incremental Utilized Capacity [MW]	26
Net Present Value Cost [M\$]	200
Net Present Value Cost per Utilized Capacity [M\$/MW]	7.6

²⁰ An exception is the December 16, 2013 directive which directed the former OPA to work with those remote First Nation communities where transmission connection is not economic and implement solutions for on-site renewable generation projects that reduce their dependency on diesel fuel and promote the use of renewable energy sources. <http://www.powerauthority.on.ca/sites/default/files/news/December-16-2013-Directive-Renewable-Energy.pdf>

²¹ http://www.premiergoldmines.com/i/pdf/HRTOR/EN/Main_ToR_fnl.pdf

Option B2	
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

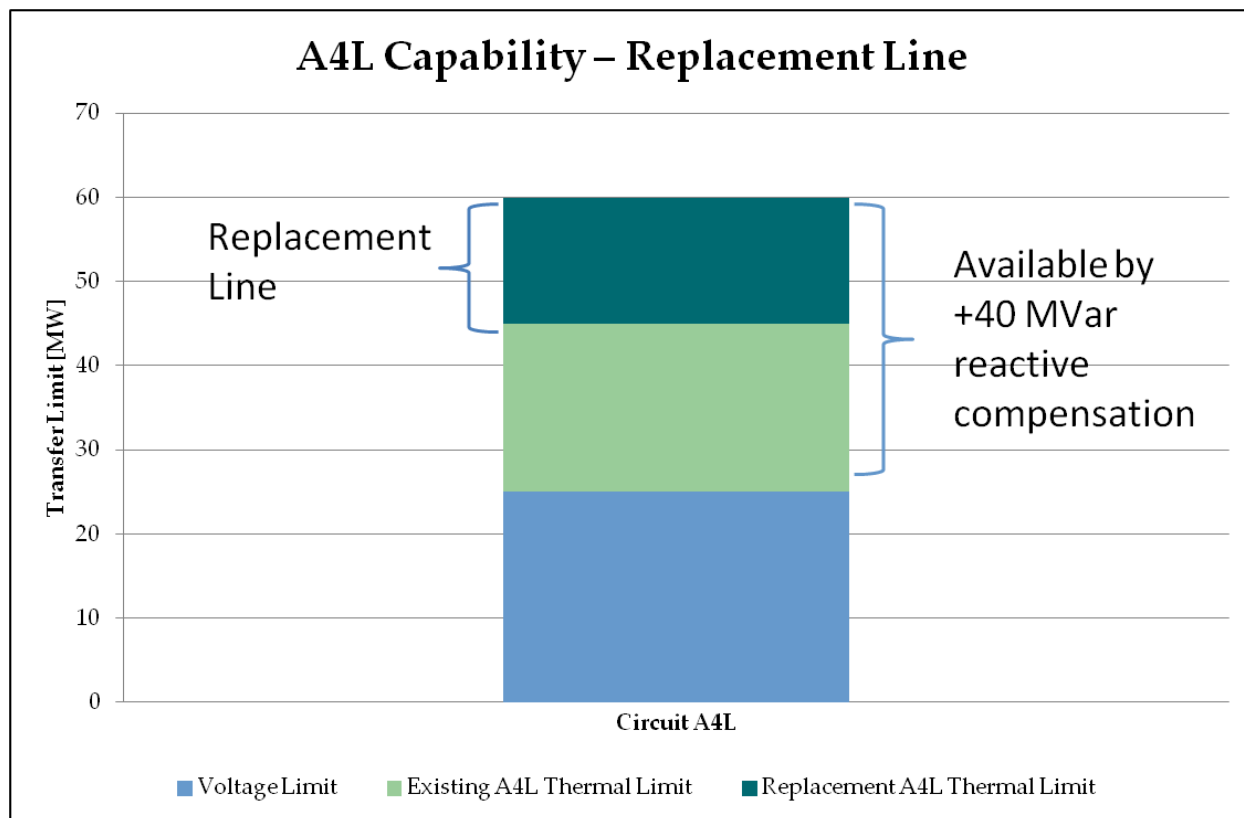
7.2.2.4 Install Reactive Compensation and Replace Sections of Circuit A4L (“Option B3”)

This option considers the needs based on load forecast Scenario B.

This option consists of replacing the sections of circuit A4L between Nipigon and Longlac with a new 115 kV line using 477 kcmil Aluminum Conductor, Steel Reinforced (“ACSR”) conductors. This would increase the ampacity of the circuit from 260 A to 310 A. If the circuit is fully compensated, this would increase the LMC to about 60 MW²² which would accommodate the full 51 MW forecast by 2020 for Scenario B.

²² The limiting section following the replacement of A4L between Nipigon Junction and Longlac is the section between Alexander SS and Nipigon Junction, which is 310 A. If this section was also replaced, the ampacity of the circuit could increase up to 620 A, which corresponds to an LMC of up to about 120 MW fully compensated. However, since forecast Scenario B only requires an LMC of 51 MW, upgrades were only considered from Longlac TS to Nipigon Junction and a full replacement of A4L was not considered further.

Figure 7-2: Increase in A4L Capability with Nipigon to Longlac replaced with a new line equipped with 477 kcmil conductors and with +40 MVar of Reactive Compensation



This option would be optimally staged by first installing +40 MVar of compensation to provide an LMC of 45 MW to accommodate load growth up to and including 2019. This would be followed by building the new line sections to be in-service for 2020. The line sections may be constructed while the existing line serves customers, if right of way space is available.

Otherwise, a bypass would be needed to allow for replacement of the existing line, which may increase costs by approximately 20%. Once the new line sections are constructed, existing facilities can be re-tapped on the new line sections. Following the installation of the new line sections, no additional reactive compensation would be required beyond the +40 MVar as the larger conductors result in a reduced voltage drop across the line. Greater load increase can then be accommodated without additional compensation.

Power flow study results are included in Appendix C and indicate that facilities are expected to perform within ratings with sufficient reliability.

The related economic analysis is included in Appendix D.

The details of the option are summarized below.

Table 7-4: Summary of Option B3

Option B3	
Incremental Utilized Capacity [MW]	26
Net Present Value Cost [M\$]	40
Net Present Value Cost per Utilized Capacity [M\$/MW]	1.5
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	No

The result of the analysis is that Options B1 and B3 (the grid-connected options) are comparable in cost based on the degree of accuracy of planning cost estimates, and are more economic than Option B2 (the off-grid generation option). Options B1 and B3 have a common first stage – the installation of a synchronous condenser or STATCOM – to accommodate phase 1 of the Geraldton mine.

7.2.2.5 Install New 230 kV Transmission Supply to Longlac and Off-Grid Generation (“Option C1”)

This option considers the needs based on load forecast Scenario C.

In order to accommodate an incremental capacity deficiency of about 60 MW, (associated with the Geraldton mine and connecting two large oil pumping stations that are located within the vicinity of the existing transmission system), an additional 230 kV supply may be installed. The 230 kV supply option would consist of a new single-circuit 230 kV line, a new 230/115 kV auto-transformer located at or near Longlac TS, the associated protection and switching facilities, and reactive compensation (including +40 MVar of reactive compensation at the Geraldton mine consistent with Options B1 and B3). Detailed routing for the 230 kV line option can only be determined through an EA process. However, for planning purposes this report has considered two conceptual routing options for cost comparisons.²³ These two routing options are generally consistent with the routing options that have been communicated to the IESO by interested

²³ A 230 kV transmission line routing other than the two concepts listed may be considered by proponents if the proposed arrangement provides equivalent or relatively better technical, economic, environmental, and social performance.

development groups and consist of an “East of Nipigon” route option, and a “West of Marathon” route option.

The East of Nipigon routing option is based on utilizing the existing Highway 11 corridor, generally running parallel with circuit A4L to Longlac TS and tapping M23L and/or M24L (the existing East-West Tie) between Marathon TS and Lakehead TS, near Nipigon. The length of the East of Nipigon route option would be approximately 150 km. The costing of this option considers single-circuit 230 kV H-frame wood poles with road access in northwestern Ontario.

The West of Marathon routing option is based on utilizing a least-distance, straight line route from the existing East-West Tie, tapping M23L and/or M24L west of Marathon, near Terrace Bay. The length of the West of Marathon route option would be approximately 100 km. The costing of this option considers single-circuit 230 kV H-frame wood poles without road access in northwestern Ontario (since it is considered to be on undeveloped land).

Figure 7-3: Option C1 illustrative²⁴ route map



The East of Nipigon route has the benefits of utilizing an existing corridor, and a lower per-distance cost (associated with road access), but is longer. The West of Marathon route option has the benefits of being more secure (since common mode failures of both A4L and a new line would be significantly reduced by a separate corridor) and is shorter. However, this option is more costly per-distance (since it has no road access), and may have greater environmental impact. Details of environmental impacts would be considered during an EA process, where different routes would be considered by the project proponent.

Finally, two pumping stations would be supplied from dedicated gas-fired generation (i.e. not interconnected with the IESO-controlled grid). This would account for the final approximately 30 MW (to total 89 MW) incremental capacity for this scenario. These stations are

²⁴ The routes depicted are for illustrative purposes only and are not an indication of suggested routing for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

geographically distant from the existing transmission system. As noted earlier, the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid. This option is included to provide existing and future customers with the full range of options that are available.

Power flow study results are included in Appendix C.

The related economic analysis is included in Appendix D.

The details of Option C1 are summarized below:

Table 7-5: Summary of Option C1

Option C1	
East of Nipigon Route Option	
Incremental Utilized Capacity [MW]	89
Net Present Value Cost [M\$]	170
Net Present Value Cost per Utilized Capacity [M\$/MW]	1.9
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes
West of Marathon Route Option	
Incremental Utilized Capacity [MW]	89
Net Present Value Cost [M\$]	165
Net Present Value Cost per Utilized Capacity [M\$/MW]	1.9
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

Under this scenario, the N-1 load security would be 45 MW. This accounts for the loss of the new circuit. In considering the N-1 contingency scenario where the 230 kV line (option) is lost, the remaining system would consist of circuit A4L, which is all that exists today. Fully compensated, circuit A4L can accommodate 45 MW.

In order to remain within facility ratings, load would need to be reduced to 45 MW following the loss of the new circuit.²⁵ The resulting N-1 load security does not satisfy ORTAC.

Provisions in ORTAC exist to allow for a customer to agree to higher or lower levels of reliability, provided the bulk system is not negatively impacted. This provides flexibility to customers in the event that ORTAC required enhancements are not cost-effective for them.

Option C2 and Option C3 result in N-1 load security that is greater than Option C1 and satisfies ORTAC.

7.2.2.6 Install New 230 kV Transmission Supply to Longlac and New 115 kV Line from Longlac to Manitouwadge (“Option C2”)

This option considers the needs based on load forecast Scenario C.

Option C2 builds on Option C1 and consists of installing a new 230 kV supply to the Greenstone area as well as installing reactive compensation (including +40 MVar reactive compensation at the Geraldton mine consistent with Option B1 and Option B3).

In addition, there are two pumping stations that are distant from the existing transmission system and would therefore require a new line if connection is preferred. This option considers installing a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS, as well as the associated protection, voltage control, and switching facilities.

This option also considers the re-termination of the Longlac TS load station on the 230 kV bus, which would be installed to terminate the 230 kV line option. This is to reduce the overall risk of load loss by distributing load supply stations across different protection zones. The cost of the re-termination has been accounted for by including the cost of new 230 kV step-down transformers.

²⁵ To reduce loading to 45 MW, considerations may be built into design configuration, or a special protection system may be installed.

Figure 7-4: Option C2 illustrative²⁶ route map



Installing switching facilities with appropriate redundancy to separately protect each pumping station can allow all four pumping stations in the area to be supplied from an expanded transmission system. The cost of this protection arrangement has been incorporated by including the cost of new in-line breaker facilities.

Power flow study results are included in Appendix C.

The related economic analysis is included in Appendix D.

The details of the option are summarized below:

²⁶ The routes depicted are for illustrative purposes only and are not an indication of suggested routing for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

Table 7-6: Summary of Option C2

Option C2	
East of Nipigon Route Option	
Incremental Utilized Capacity [MW]	89
Net Present Value Cost [M\$]	165
Net Present Value Cost per Utilized Capacity [M\$/MW]	1.8
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes
West of Marathon Route Option	
Incremental Utilized Capacity [MW]	89
Net Present Value Cost [M\$]	160
Net Present Value Cost per Utilized Capacity [M\$/MW]	1.8
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

Option C2 would satisfy ORTAC and is comparable to the cost of Option C1 based on the degree of planning cost estimates.

7.2.2.7 Install New Generating Plant Near Longlac and New 115 kV Line from Longlac to Manitouwadge (“Option C3”)

This option considers the needs based on load forecast Scenario C.

An alternative to Option C2 is to develop a generation-based option to provide a secure supply. Option C3 includes installing a new large grid-connected generation facility near Longlac TS, and building a new 115 kV single-circuit line to connect the two distant pumping stations. This option does not require additional reactive compensation devices, as the generation plant would be able to provide the required voltage support and short-circuit level to the area. Studies indicate that SVCs would still be required to address credible outage conditions, which have been factored into the costing of this option.

The available capacity of the generating plant would need to be 80 MW at a minimum to provide a secure supply under applicable criteria. For a natural gas-fired generation plant, this would correspond to the summer capability of the plant of 80 MW with at least one unit out of

service, a substation with at least two step-up transformers, and an SPS to automatically shed load in the event of additional outage and/or contingency conditions. For the purpose of establishing planning level cost estimates, a 6x18 MW arrangement has been assumed. Other feasible arrangements may be considered.

This option is depicted in Figure 7-5 below.

Figure 7-5: Option C3 illustrative²⁷ route and generation map



The generating facility would need to be dispatched-on to at least minimum loading whenever the load in the area is expected to exceed 25 MW. The generation facility would also need to output to a level that ensures the local transmission facilities are able to respect N-1 conditions, which is limited by the 45 MW thermal capability of A4L. Based on the forecast energy profile

²⁷ The routes and generation sites are for illustrative purposes only and are not an indication of suggested routing/siting for project developers. The routing depicted was used to establish line lengths to develop planning level cost estimates.

of the area, the generation is expected to operate due to local constraints 100% of the time, and would need to produce on average approximately 85 GWh per year in 2018-2019 and 425 GWh per year in 2020 and onward.

Power flow study results are included in Appendix C.

Related economic analysis is included in Appendix D.

Table 7-7: Summary of Option C3

Option C3	
Incremental Utilized Capacity [MW]	89
Net Present Value Cost [M\$]	350
Net Present Value Cost per Utilized Capacity [M\$/MW]	4.0
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

7.2.2.8 Install Off-Grid Generation (“Option C4”)

This option considers the needs based on load forecast Scenario C

Similar to Option B2, a possible option is to serve LDC demand with the existing electricity infrastructure, and for the Geraldton mine and the major pipeline project to supply their own facilities with on-site natural gas generation.

As indicated in Section 7.2.2.3, Option B2 would include provisions for 56 MW of power generation capacity at the Geraldton mine. Additionally this option would include provisions to supply each pumping station with off-site power generation and would not be interconnected with the IESO-controlled grid. For the purpose of establishing cost estimates, 9.5 MW units are assumed.

As noted earlier, the IESO does not generally procure generation to meet future demand that is not connected to the IESO-controlled grid. This option is included to provide existing and future customers with the full range of available options. Based on the average annual energy forecast for the Geraldton mine and the pumping stations, the energy production is expected to be approximately 185 GWh per year in 2018-2019, and 555 GWh in 2020 and onward.

Table 7-8: Summary of Option C4

Option C4	
Installed Capacity [MW]	57 (6x9.5) + 76 (8x9.5)
Incremental Utilized Capacity [MW]	89
Net Present Value Cost [M\$]	510
Net Present Value Cost per Utilized Capacity [M\$/MW]	5.7
Meets Forecast Scenario A:	Yes
Meets Forecast Scenario B:	Yes
Meets Forecast Scenario C:	Yes

The result of the analysis is that Options C1, C2 and C3 are more economic than Option C4 (the off-grid option). The most economic Options - C1 and C2, have a common first stage – the installation of a synchronous condenser or STATCOM – to accommodate phase 1 of the Geraldton mine. Finally, Option C2 would result in N-1 load security that is greater than Option C1.

7.3 Long-Term Considerations for Near-Term Planning

When establishing the near-term elements of a long-term plan, it is important to consider the impact of certain developments and/or projects that are beyond the near-term (present-5 years) time frame. The longer-term considerations for the Greenstone-Marathon Sub-region include the potential for additional mining in the Greenstone area, a North-South corridor option to the Ring of Fire mining development and the remote First Nation communities in the vicinity, as well as the impact of connection requirements for the Little Jackfish hydroelectric project.

7.3.1 Additional Mining Potential in the Greenstone Area

The Working Group can only develop plans for mining projects for which there is a quantified electrical demand level that has been established by the project developer and is communicated to the Working Group, or to the IESO via a feasibility study or SIA request. The Working Group is aware that there are additional mining claims in the Greenstone area in addition to the projects being considered for the near term in this report. Additional mining claims in the Greenstone area present an opportunity for coordinated long-term electricity planning and cost sharing as these developments could result in higher utilization of new facilities. Electricity plans, especially those driven by resource-based project developments, need to consider the value of long-term flexibility to enable opportunities in the long-term.

7.3.2 Ring of Fire Considerations for Near-Term Planning

Near-term elements of the long-term plan should consider the value of flexibility for the long term. For instance, the 2015 North of Dryden IRRP recommended that any multi-use corridor to the Ring of Fire consider the potential need for a new transmission line because of the efficiencies in cost and reduction in environmental impacts that are expected from shared land use along the corridor. If a decision is made to secure a North-South corridor to the Ring of Fire, and the corridor includes consideration for a new transmission supply, it would have important implications for near-term elements being considered for the Greenstone-Marathon IRRP.

If a North-South transmission line is developed to the Ring of Fire, it would require a 230 kV connection to the East-West Tie and routing to the Geraldton area consistent with the transmission options that have been considered as part of Sections 7.2.2.5 and 7.2.2.6, before extending north to the Ring of Fire area. In other words, if a North-South transmission line is developed to the Ring of Fire, transmission supply to Geraldton would still be required and any recommendation for the near term that is not consistent with the options considered in Sections 7.2.2.5 and 7.2.2.6 would represent a lost economic opportunity. The opportunity cost, when considering Ring of Fire options, reinforces that electricity plans, especially those driven by resource-based project developments, need to consider the value of long-term flexibility to leverage opportunities in the long term.

7.3.3 Little Jackfish Considerations for Near-Term Planning

This subsection identifies the aspects of the Little Jackfish hydroelectric project that may interact with near-term elements of the Greenstone-Marathon plan.

Connection of the Little Jackfish project to the existing system would require a 230 kV connection line from the project site to the East-West Tie. This connection line would be approximately 180 km long. The southern half of the transmission connection line routing that was considered by Ontario Power Generation (“OPG”) in their project description²⁸ (pursuant to the Canadian Environmental Assessment Act) was largely consistent with the East of Nipigon transmission option routing being considered as part of Options C1 and C2 and identified in Sections 7.2.2.5 and 7.2.2.6 of this report. If the East of Nipigon transmission line routing is pursued, the cost of building the southern portion of the line option between the East-

²⁸ http://www.opg.com/generating-power/hydro/projects/little-jackfish/Documents/LJF_Project_Description.pdf

West Tie connection point and the area near the Town of Beardmore would be shared among multiple parties and would result in a reduced cost of connection for all parties in accordance with the TSC, including the Little Jackfish proponents.²⁹

If the need for additional generation supply is identified in the region and a transmission connection consistent with the East of Nipigon route identified in Sections 7.2.2.5 and 7.2.2.6 is pursued, the IESO will review the suitability of the project as an option to meet potential supply needs. This review would include an update to the economic merits of the Little Jackfish project to account for the reduced line connection cost.

7.4 Near-Term Plan Implementation Considerations

The near-term needs identified in the Greenstone area are driven by a few potential large industrial loads that may proceed and choose to connect to the transmission system. This presents significant uncertainty for customers and project developers in the area.

7.4.1 Implementation of Local Transmission Options

Local transmission serves the purpose of reliably supplying specific customer demand. Consistent with the TSC, beneficiaries of transmission facilities must make a capital contribution. This is an established requirement and applies to all customers province-wide.

When developing new local transmission, as defined by the OEB, transmitters require financial commitment for capital recovery before incurring any costs associated with developing transmission. This commitment is usually in the form of an agreement between the transmission company and the customer. Customers are typically required to commit to a Capital Cost Recovery Agreement (“CCRA”) with the incumbent transmitter before the incumbent transmitter commits investments for development work. This report documents the Working Group’s assessment of need and options available for these customers.

7.4.2 Implementation of Grid-Connected Generation Options

The IESO procures generation resources to supply the Ontario system demand, and when doing so, seeks to minimize marginal energy costs for all Ontario ratepayers. In considering generation options, the IESO takes into account feedback from the local community, whether

²⁹ The precise amount would depend on the final decision for cost contribution determined through a Leave to Construct application and would be consistent with the TSC. The TSC requires that beneficiaries pay in proportion to their usage of the facility.

the lowest marginal cost resource can be sited in that area and whether that option could defer or completely address the needs.

The IESO does not generally procure new generation resources to supply a set of customers in a particular local area if that generation results in a relatively higher marginal cost compared to other available options. If the benefitting customers wish to establish a capacity and energy agreement directly with the generation company for grid-connected generation as opposed to other potential supply options (e.g., local transmission or off-grid generation), then they may do so. The generator would still be subject to all the requirements to connect to the IESO-controlled grid.

The onus is on the customer to engage the electricity service provider that meets its needs. This report documents the Working Group's assessment of need and options available for these customers.

7.4.3 Implementation of Off-Grid Generation Options

The IESO does not procure generation to meet future demand that is not connected to the IESO-controlled grid. Therefore, it is the responsibility of the customer to develop these options.

The Working Group has developed some off-grid generation options for the purpose of illustrating a planning level cost comparison with grid-connected options to inform customers.

8. Engagement Activities

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation.

8.1 Early Communication and Engagement Meetings

Early communication and engagement activities for the Greenstone-Marathon Interim IRRP were initiated in October 2014 as part of a series of meetings with communities and stakeholders to discuss electricity planning initiatives across Northwest Ontario. The main objective of the meetings from a regional planning perspective was to introduce attendees to the regional planning process and the Northwest Ontario Scoping Assessment process for the regional planning studies being initiated in the area, as well as discuss upcoming engagement activities. Various meetings were held with a broad range of attendees including municipal representatives, First Nation and Métis community members, federal and provincial representatives, electricity customers, CVNW, transmission and generation project developers, and others.

8.2 Northwest Ontario Scoping Assessment Outcome Report

The draft Northwest Ontario Scoping Assessment Outcome Report was posted to the IESO website in December 2014 for comment. Feedback on the draft report was received from the Municipality of Greenstone indicating the need for an accelerated timeline for the Greenstone area plan. In response, the Working Group added an interim document on the near-term elements to the Terms of Reference for the Greenstone-Marathon IRRP. This report represents the interim document.

8.3 Municipal Meetings

Meetings with area municipalities are one of the first steps in engagement for all regional plans. In April 2014, the Working Group held group municipal meetings in Marathon and Greenstone to discuss the findings and options developed to date. Attendees were generally pleased with the progress of the plan, and indicated that planning needs to be cognizant of the implementation risks involved and the need to ensure electricity prices do not increase unnecessarily.

8.4 First Nation and Métis Community Meetings

On May 11, 2015 the IESO met with the Board members of Waaskiinaysay Ziibi Inc. (“WZI”) and Chief Pelletier, Gustafson and Nelson of Red Rock Indian Band, Whitesand First Nation and Animbiigoo Zaagi’igan Anishinaabek, respectively. Waaskiinaysay Ziibi Inc. is an economic development corporation established by five First Nations: Red Rock Indian Band, BNA, BZA, AZA, and Whitesand First Nation (“WSFN”). The feedback received from WZI focused on the concern that infrastructure be planned so that environmental disturbance is minimized. Waaskiinaysay Ziibi Inc. requested that, when possible, existing infrastructure corridors are optimally utilized before developing a new corridor resulting in a new disturbance.

On May 11, 2015 the IESO met with Chief Michano of Ojibways of Pic River First Nation. A follow-up discussion with additional community members may be required for the longer-term elements of the plan.

On May 12, 2015 the IESO met with Band staff and a Councilor of Pic Mobert First Nation. The feedback from community members was that decisions regarding electricity should not result in unnecessary price increases. Community members also stressed the need for greater community-level economic development opportunities for First Nations in general.

The IESO invited all other local First Nations communities and Métis councils to similar meetings and remains open to further engagement with those communities on the plan.

8.5 Formation of Local Advisory Committees and Future Engagements

Two Local Advisory Committees (“LACs”) are being established for the Greenstone-Marathon Sub-region IRRP - a LAC open to nominations from all communities and stakeholders, and one specifically for First Nation communities. The purpose of a LAC is to establish a forum for members to be informed of the regional planning processes and to provide their input, recommendations, information on local priorities, and ideas on the design of community engagement strategies. The first meeting of the LACs will be held on June 29, 2015 with additional meetings and community engagement to take place in fall 2015.

8.6 Additional Meetings and Presentations

The IESO recognizes CVNW’s unique mandate that includes investigating and making recommendations to NOMA on issues related to energy in the Northwest Region. The IESO

continues to meet regularly with CVNW to discuss the status of electricity planning for northwestern Ontario.

A presentation on electricity planning in Northwest Ontario was delivered at the NOMA Annual General Meeting in spring 2015. This presentation included a high-level status update on the development of the Greenstone-Marathon area Interim IRRP.

9. Recommended Near-Term Plan

The following elements of the Greenstone-Marathon IRRP are recommended for near-term development to address demand forecast Scenarios A, B, or C. These scenarios are based on the Working Group's understanding of the various long-term opportunities, and on feedback from the community.

Demand Scenario A

The existing system is sufficient to meet the demand requirements presented in Scenario A. To maintain the reliability of circuit A4L, continued routine maintenance and sustainment activities consistent with Hydro One's maintenance practices and sustainment plans are expected to be adequate and meet planning criteria.

Demand Scenario B and Demand Scenario C

Demand requirements for Scenarios B and C are the same until 2020 (Stage 1) and the Working Group therefore recommends the following to address Stage 1 requirements for Scenarios A and B:

Recommended Stage 1

- Install +40 MVar of reactive compensation at the Geraldton mine in the form of either a synchronous condenser or STATCOM, to be in-service coincident with the first phase of the mine – **2018**

By initially installing reactive compensation, this effectively utilizes the existing system without incurring any additional costs. The associated NPV cost of +40 MVar of compensation is approximately \$5 million.

Demand Scenario C

If, in addition to the Geraldton mine, the gas to oil pipeline conversion project proceeds and commits to electricity service according to schedule (2020), and consistent with Scenario C, the Working Group recommends:

Recommended Stage 2a

- Install a new 230 kV single-circuit line from the East-West Tie near Nipigon or Marathon to Longlac, new 230/115 kV auto-transformer and related switching and voltage control facilities at Longlac TS to be in-service coincident with the second phase of the Geraldton mine and pumping stations loads – **2020**
- Install a new 115 kV single-circuit line from Longlac TS to Manitouwadge TS and related switching and voltage control facilities, to be in-service coincident with the pumping station loads – **2020**

Under Scenario C, a new 230 kV transmission supply to Longlac is the most economic option. The associated NPV cost of a new 230 kV supply to the area including associated line, transformation, switching, and terminations is approximately \$70 million.

This option maintains long-term flexibility for a North-South corridor to the Ring of Fire. From a long-term perspective, it is advantageous to develop a transmission supply to Longlac, rather than installing large grid-connected generation.

Should the pipeline developer decide to connect all pumping station loads in the Greenstone-Marathon Sub-region to the transmission system with N-1 supply security, it is recommended that a new 115 kV transmission line linking Longlac TS and Manitouwadge TS be developed. The associated NPV cost of the new 115 kV single-circuit line, compensation, in-line breaker stations and switching facilities is approximately \$90 million.

The total NPV cost of Stage 2a is approximately \$160 million.

Figure 9-1: Recommended Stages 1 and 2a



Demand Scenario B

If the second phase of the Geraldton mine proceeds (2020), but the gas to oil pipeline conversion project does not proceed or does not commit to grid supply, consistent with Scenario B, the Working Group recommends:

Recommended Stage 2b

- Replace the existing sections of circuit A4L, or the Geraldton mine developer may pursue on-site generation³⁰ on the order of a 2x10 MW gas generating facility, to be in-service coincident with the second phase of the Geraldton mine – 2020

If no additional customers materialize beyond the demand level consistent with Scenario B, it is more economic to supply the second phase of the Geraldton mine (2020) by either replacing the existing sections of circuit A4L between Nipigon Junction and Longlac TS with a higher capacity line (NPV cost of \$35 M) or the Geraldton mine developer may implement on-site generation comprising of a 2x10 MW gas generating facility (NPV cost of \$50 M).

³⁰ If the generation can operate in island-mode, it may be advantageous to pursue this option due to the inherent supply diversity that it offers in comparison to replacing circuit sections of A4L. The customer may also wish to investigate conservation incentives that the IESO offers, such as the IAP, to compliment this option.

The near-term elements of the IRRP are illustrated in the figures below.

Figure 9-2: Recommended Stages 1 and 2b



10. Options for Meeting Long-Term Needs

10.1 Approaches to Meeting Long-Term Needs

(This section is intentionally left blank. To be developed in Final 20-year IRRP report)

10.2 Recommended Actions and Implementation

(This section is intentionally left blank. To be developed in Final 20-year IRRP report)

11. Conclusion

(This section is intentionally left blank. To be developed in Final 20-year IRRP report)

TAB 6

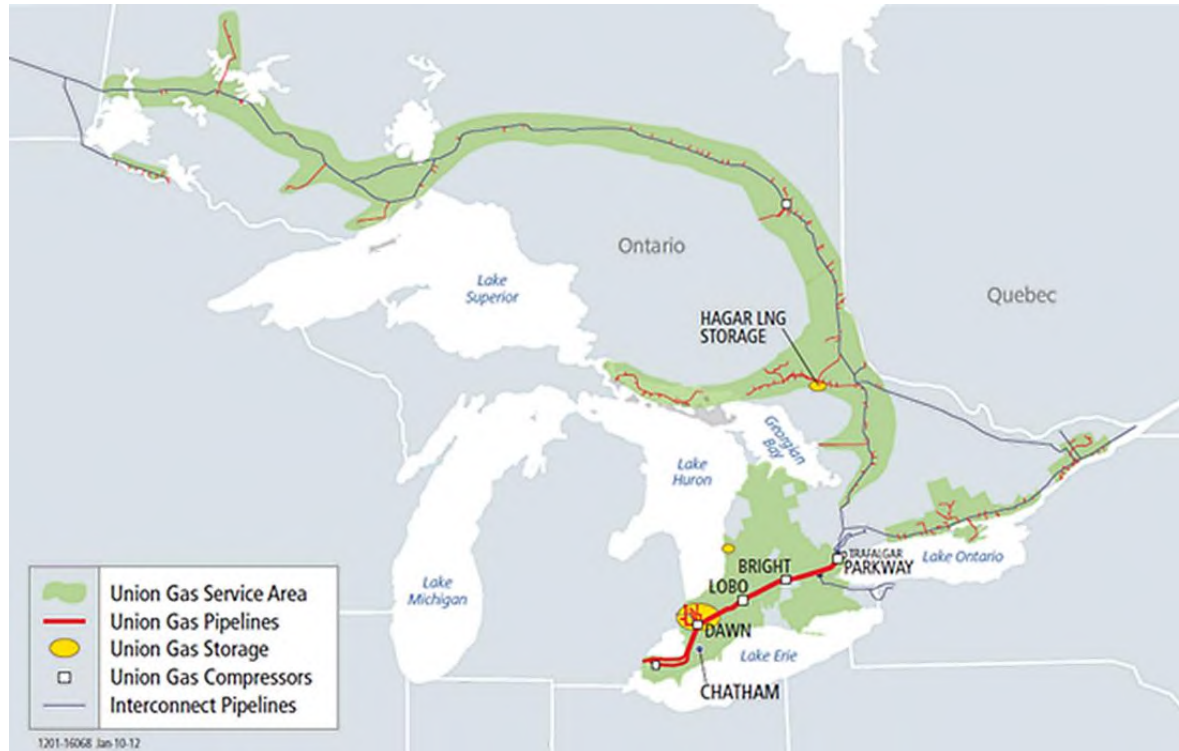


2013 NORTHWESTERN ONTARIO REGIONAL CONFERENCE

The Important Role of Natural Gas In Ontario's Energy Future

Dave Simpson
VP, Infranchise Sales, Marketing & Customer Service

Union Gas: A Spectra Energy Company



Union Gas – By The Numbers In Ontario, we:

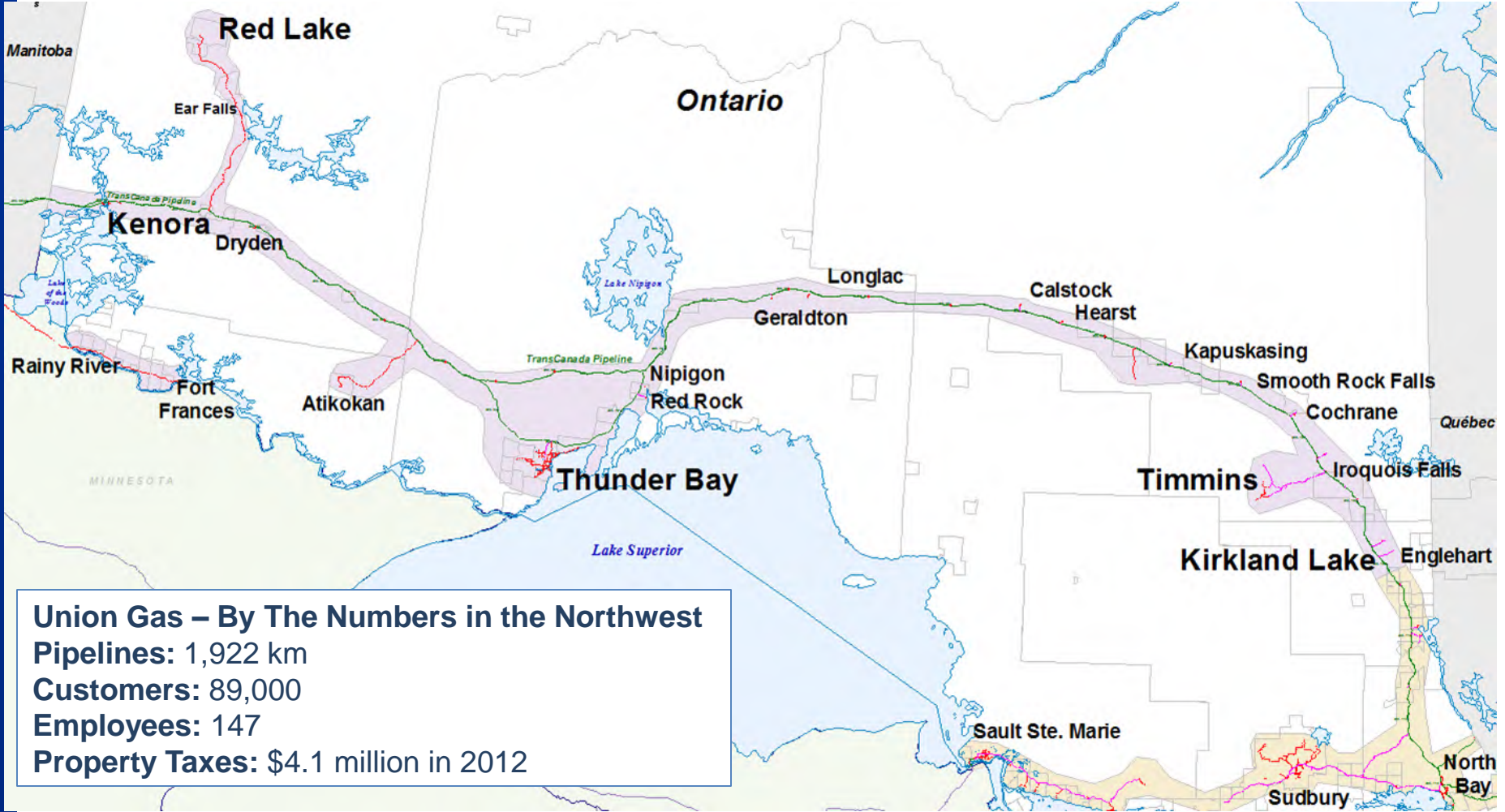
- Serve about **1.4M** retail customers
- Own and operate about **67,000 km** of pipeline
- Maintain **155 Bcf** of storage in **23** underground reservoirs
- Employ **2,200** workers
- Hold **\$5.8B** in assets
- Pay almost **\$63M** in property taxes (2012)
- Realize approximately **\$1.8B** in annual revenue

We make a significant contribution to Ontario's economy

Here In The Northwest



Filed: 2016-03-22
EB-2016-0004
A Spectra Energy Company
Page 000346



Union Gas – By The Numbers in the Northwest
Pipelines: 1,922 km
Customers: 89,000
Employees: 147
Property Taxes: \$4.1 million in 2012

Something To Celebrate





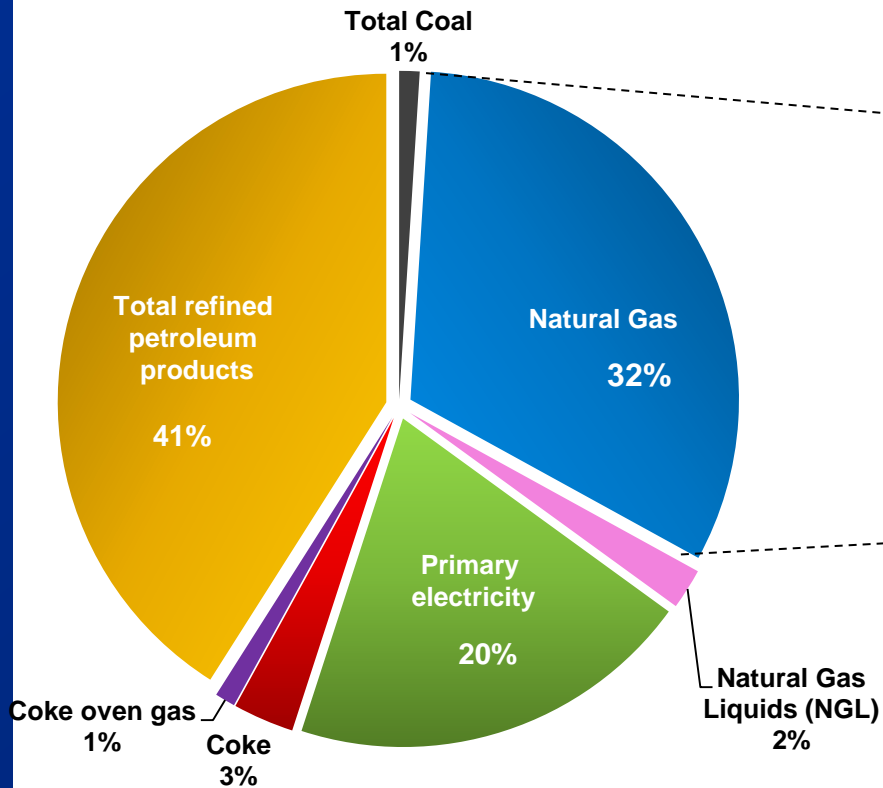
Opportunities for Ontario

- Natural gas prices in Canada have been on a steady decline since mid-2008 due to increasing supply and economic trends
- Residential savings of **\$275-\$400/year**
- Commercial customer savings of **\$9,000-\$15,000/year**
- Industrial customer savings of **\$10-20 million/year**
- **\$3-5 billion/year** in savings to Ontario consumers

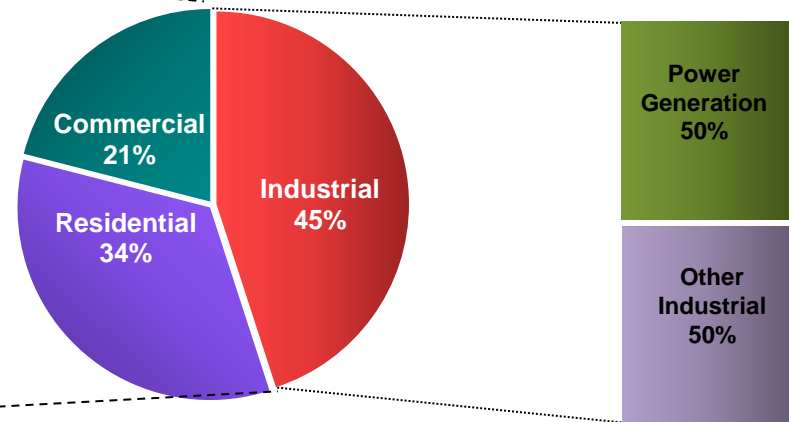


Ontario's Primary Energy Mix

Total Energy Mix (TJ%)



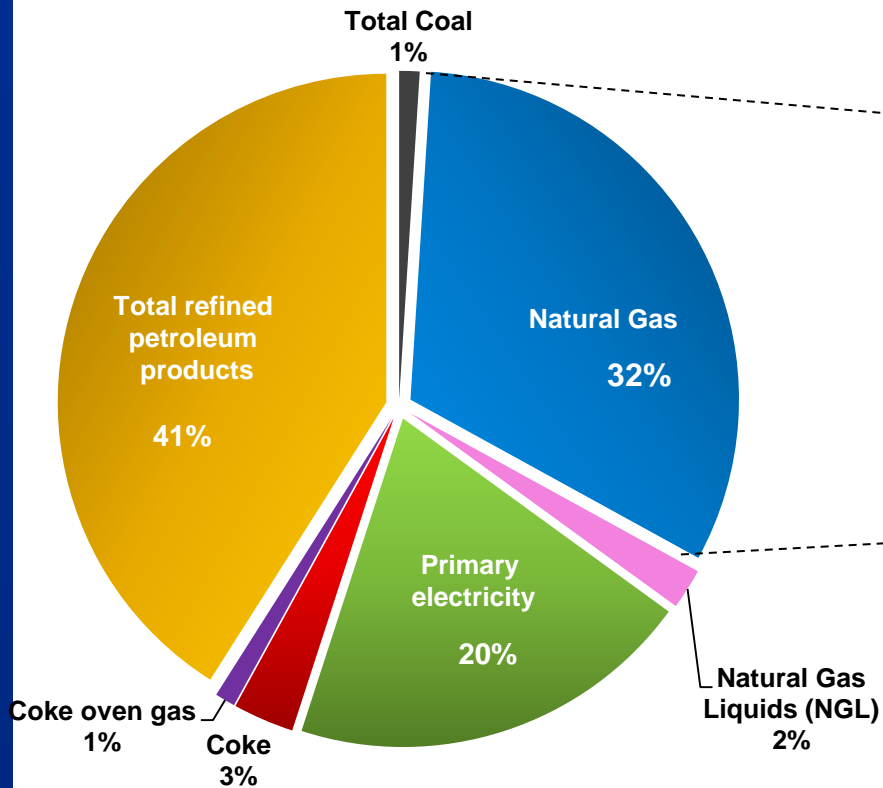
Natural Gas Throughput



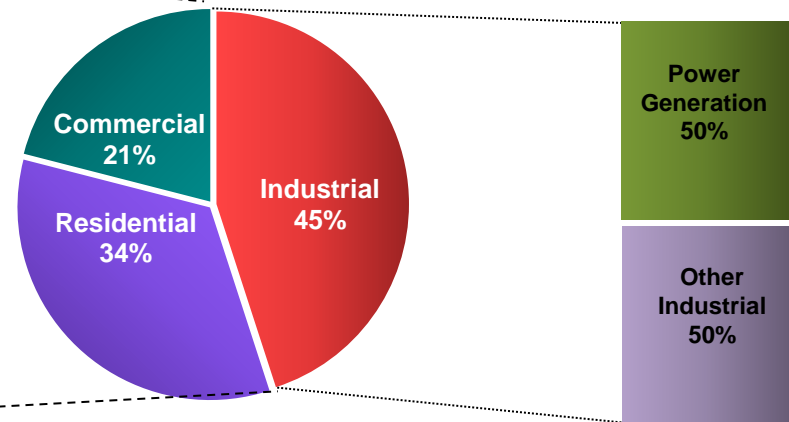
- Residential **95%** of Customers
- Commercial **4.8%** of Customers
- Industrial **.02%** of Customers

Ontario's Primary Energy Mix

Total Energy Mix (TJ%)



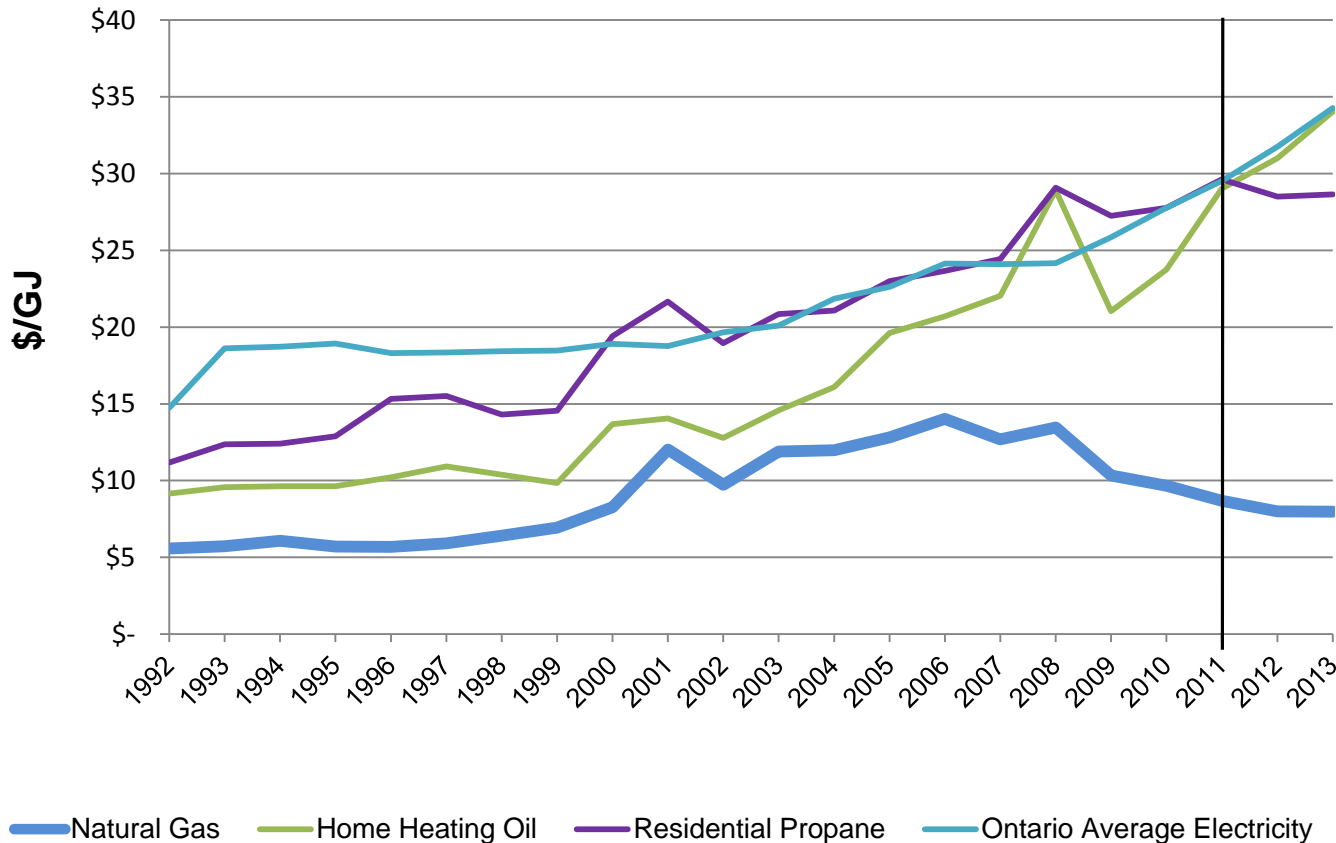
Natural Gas Throughput



- Residential **95%** of Customers
- Commercial **4.8%** of Customers
- Industrial **.02%** of Customers

Ontario's Total Residential Bill Prices

Burner Tip & Commodity Prices

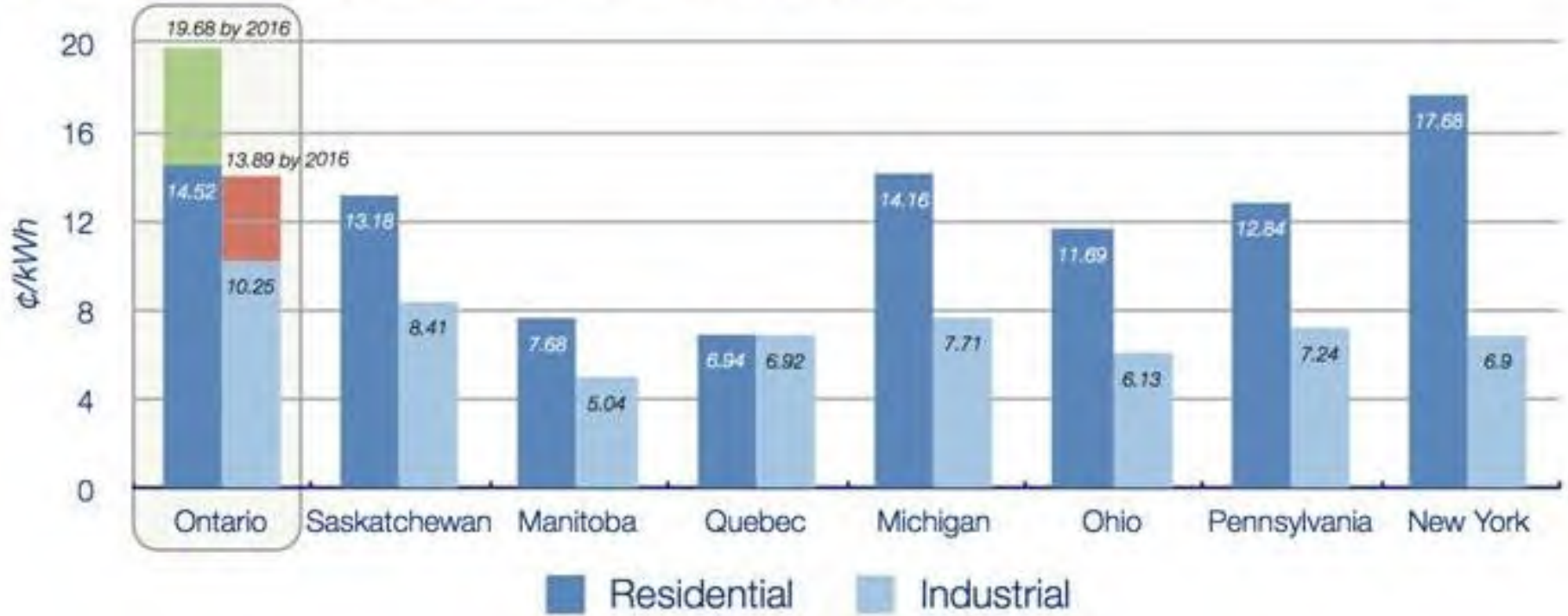


("Ontario Average Electricity" is the average price of all electricity distributors across Ontario as reported by Statistics Canada; HST and Ontario Clean Energy Benefit are not included)

Natural gas prices are lower than they have been in a decade

Ontario's Electricity Rates & Surrounding Provinces/States

(Based on average residential and industrial consumption HOEP + global adjustment)



Ontario's electricity rates need to be competitive

Natural Gas A Natural Option For The North

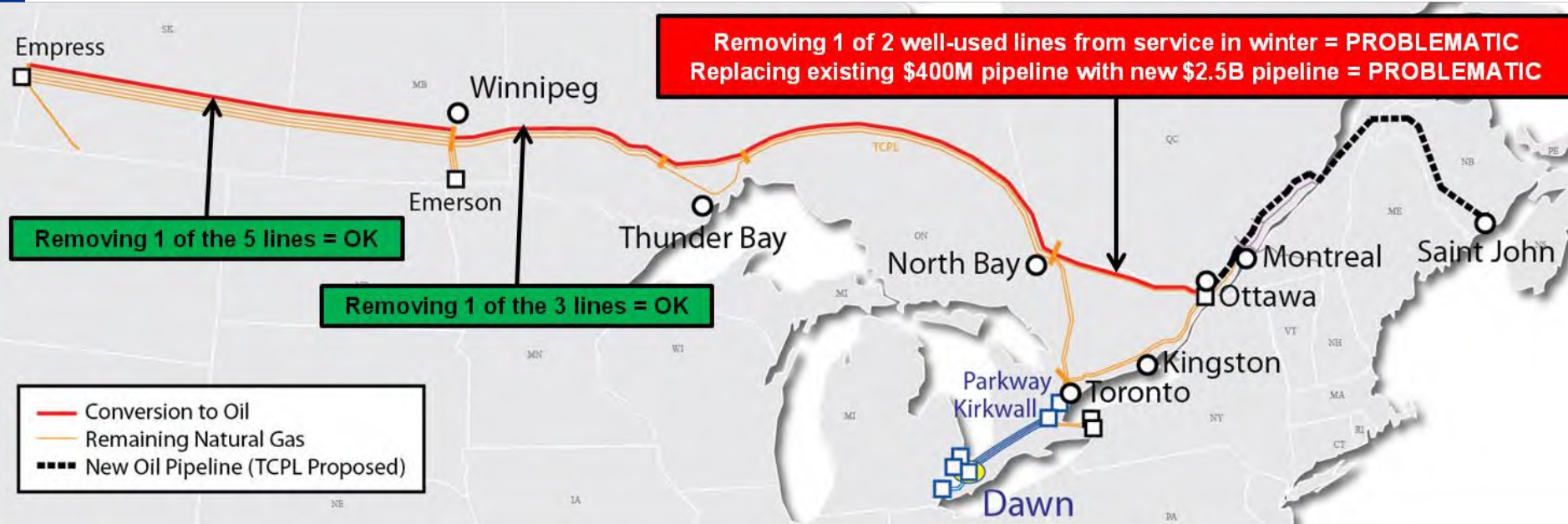


Exploring opportunities to support growth and prosperity

- CNG/LNG applications for:
 - Serving remote communities through “off pipe” service
 - Mining developments like the Ring of Fire
- ‘Traditional’ pipeline connections for:
 - Communities not currently connected to distribution lines
 - New power generation (i.e. OPA’s recent *North of Dryden* report recommends siting of a new natural gas fired plant in NW Ontario)

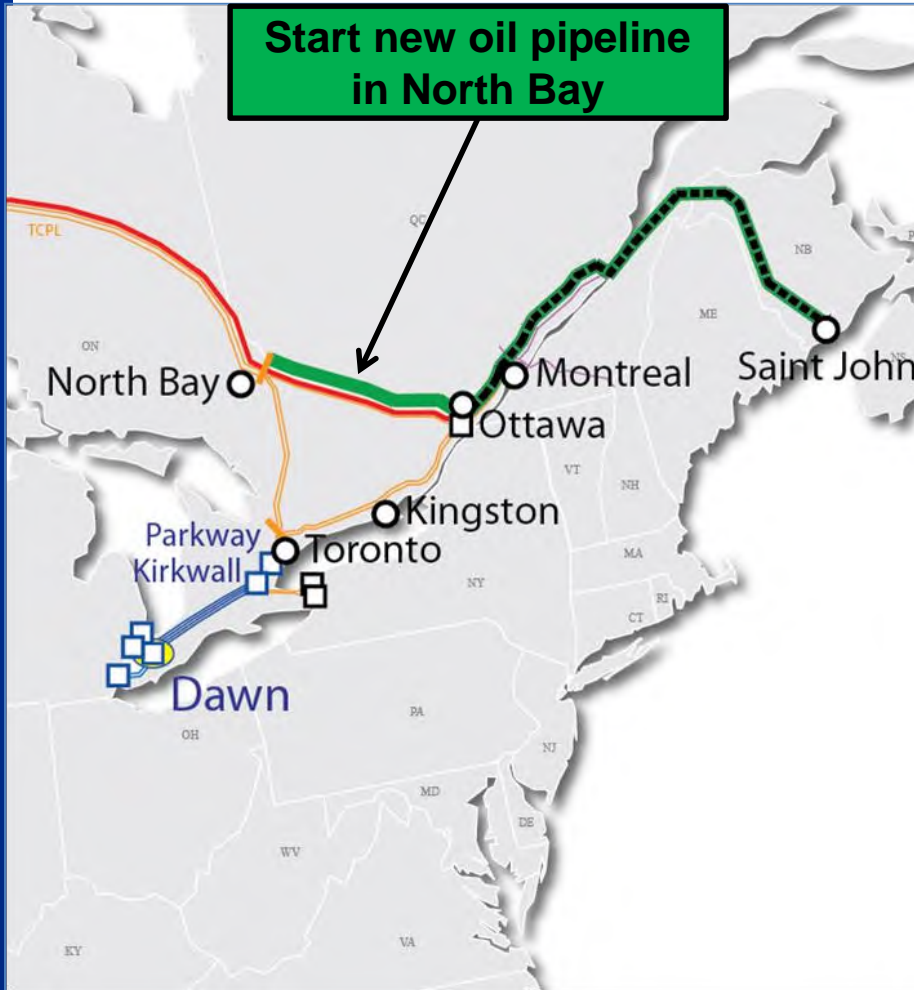
Natural gas can provide northern communities with options for industrial applications and power generation

Energy East As Currently Proposed



In principle, Union Gas supports TransCanada's proposed oil conversion project

Establishing Winning Conditions For Energy East



- Specific mitigation that would ensure Ontario consumers aren't disadvantaged:
- Start the construction of the new oil pipeline in North Bay
- Ensure conversion of existing infrastructure accomplished without increasing current gas market cost in Ontario & Quebec (i.e. \$400M)

Be engaged, stay informed, help to ensure a positive outcome

Q&A



uniongas

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Union Gas Celebrates Completion of Red Lake Pipeline Project*Affordable, clean natural gas begins flowing in northern community*

Oct. 30, 2012

Red Lake, ON – Union Gas executives were joined in Red Lake today by government dignitaries, representatives from mining company Goldcorp and special guests, to celebrate the completion of a pipeline project that is delivering clean, affordable natural gas to local residents and businesses.

Mike Shannon, vice president of operations at Union Gas and David Sword, northwest district manager for the natural gas utility, were joined by Ontario Natural Resources Minister Michael Gravelle, MPP for Kenora-Rainy River, Sarah Campbell, Red Lake Mayor Phil Vinet and Goldcorp superintendent of community relations Mark Vermette, at the Red Lake Regional Heritage Centre to light a ceremonial natural gas flame marking this important occasion for the community.

"Union Gas has been delivering affordable, clean and reliable natural gas to over 400 communities in Ontario for more than a century," Shannon said. "We're proud of our longstanding community partnerships and on behalf of the 2,200 employees at Union Gas, we are pleased to continue to grow our relationship in northern Ontario."

The \$40 million project was funded cooperatively by the federal and provincial governments, Goldcorp, the Municipality of Red Lake and Union Gas. Natural gas can save consumers 50 to 70 per cent compared to electricity, fuel oil and propane.

"On behalf of Council, Staff and residents, I would like to thank Union Gas for investing and having confidence in the Red Lake Area. We look forward to a partnership with Union Gas that will be beneficial to all for many years to come," said Vinet. "This new clean, efficient and economic form of energy will provide new opportunities for our residents and businesses. We welcome Union Gas to Red Lake!"

The heating and plumbing community in the Red Lake region is already busy responding to requests for new furnaces, water heaters and other pieces of natural gas equipment.

"I am delighted that the provincial government could help support Union Gas in the construction of this pipeline project. It will provide the residents and businesses of the Municipality of Red Lake with clean, affordable, and reliable natural gas service," said Gravelle. "This project has supported the creation of over 100 jobs, financially benefited and stimulated the local economy, and will most certainly encourage further investment in Northern Ontario."




Natural gas is now available at the Goldcorp mine sites and in October, service began rolling out to individual homes and businesses in phases. Gas service will be available in all areas by the end of November.

"This is another example of Goldcorp's commitment to sustainability and long-term value creation for the communities in which we operate," said Goldcorp's Vermette. "This project will not only satisfy our anticipated growth and save costs; our employees and the community here in Red Lake will benefit from clean, low-cost energy for generations to come."

Added Tony Clement, Minister for FedNor: "The Government of Canada is proud to have invested in the natural gas pipeline connecting Red Lake's business and commercial districts, which will serve as a catalyst for regional economic development, enhancing business competitiveness and attracting private sector investment for years to come. Today's milestone celebration is a tribute to the dedication and determination of all involved in making this community priority a reality."

Applications for gas service have been gathered and processed through the summer months. Over 400 applications have been received to date and Union Gas will continue to install services for customers in subsequent years.

Over the past century, Union Gas has been privileged to work in more than 400 Ontario communities. In addition to natural gas delivery services for homes and businesses, Union Gas has contributed to the province through significant economic investments, hundreds of jobs, millions in municipal taxes, energy efficiency programs, thousands of volunteer hours helping community organizations, major charitable giving and sponsorships. Last year alone, Union Gas and its employees contributed \$3 million to charitable organizations across Ontario, including more than \$900,000 to United Way. For more information visit [uniongas.com/community \(/community\)](http://www.uniongas.com/community (/community)).




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TAB 8

Going greener at Red Lake

November 01, 2012



Natural gas conversion is the latest sustainability initiative at Goldcorp

Red Lake Gold Mines is making final preparations to start up a newly constructed natural gas line that will not only benefit production at its operations, but people in nearby communities and the planet.

The conversion to natural gas at Goldcorp's Red Lake operations in northern Ontario was made official with a "Red Lake Flame Lighting" ceremony hosted by Union Gas yesterday. Red Lake Gold Mines employees were on hand to celebrate the switch to greener, cleaner natural gas, alongside the Mayor of Red Lake and representatives from the provincial and federal government and Union Gas.

The event celebrates the partnership between Goldcorp, Union Gas and all three levels of government in helping to create, finance and construct the 43-kilometre pipeline that was built from a historic northern Ontario mine site along Highway 105 into the Red Lake region. Natural gas will become the key energy source for Red Lake Gold Mines, and will also be accessible to approximately 5,000 people living in communities around the mining operations, as well as local businesses.

"It's a great project for Goldcorp and the community is very excited about it," says Mark Vermette, Community Relations Superintendent at Goldcorp's Red Lake Gold Mines. "It's another sustainability project that involves the community in which we operate."

The team at Red Lake Gold Mines started looking into the natural gas option in late 2009, after realizing that the current hydro capacity could not fully support production growth. Capacity would be further constrained with the development of the nearby Cochenour project, scheduled to begin production in early 2014, and may also limit or delay Goldcorp's future mine growth. "We wanted to be proactive and ensure alternative forms of energy were available," says Curtis Pedwell, Maintenance Manager at Red Lake Gold Mines.

Diesel was one option, but the Company felt it was not cost effective or environmentally friendly. Pedwell's team recalled there was a capped natural gas well at the old Griffith Mine site located a few dozen kilometres away, so they

began looking at ways to tap it as a new source for their operations.

A pre-feasibility study analyzed the cost of installing a pipeline in the ground along the highway into Red Lake, measured the potential of this renewed power source and determined the best way to convert existing propane-heating loads to natural gas. The study showed the move would not only pay for itself in five years, but could potentially cogenerate up to 30 megawatts of additional power if required.

"We quickly realized that natural gas for cogeneration would be efficient and environmentally friendly," Pedwell says. "It also helps to secure any future energy demands that we may face as we continue to grow our operations. Following months of negotiations with representatives from the municipal, provincial and federal governments, Goldcorp championed the investment to bring natural gas to Red Lake Gold Mines as well as the homes and businesses in the surrounding region."

The biggest impact from an environmental standpoint is the majority of the homeowners in the area heat their homes with fuel oil. The impact of conversion alone is a reduction of 250,000 to 350,000 tonnes of carbon emissions being displaced over the life of the project," Pedwell says.

"Allowing our employees and the community here in Red Lake to benefit from clean, low-cost energy was at the forefront of our decision to proceed with this project."

TAB 9



Red Lake Margaret Cochenour Memorial Hospital

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Board Chair
Terry Burse

Chief Executive Officer
Paul Chatelain

MEDIA RELEASE

Red Lake Margaret Cochenour Memorial Hospital Upgrades Hospital and Conserves Energy

RED LAKE, April 10, 2014 – Red Lake Margaret Cochenour Memorial Hospital today announced the completion of a comprehensive Energy and Facility Renewal Program. As a result of the energy-efficient building improvements and infrastructure upgrades, the program is expected to save approximately \$221,000 in utility costs annually, which is guaranteed by Honeywell under an energy-savings performance contract.

The program will also bring about environmental benefits, cutting carbon dioxide emissions by an estimated 176 metric tonnes annually – equivalent to removing close to 60 medium size cars from the road each year according to figures from Environment Canada.

“This program has provided an opportunity for our hospital to upgrade some of our aging systems through a guaranteed funding mechanism,” says Paul Chatelain, CEO of Red Lake Margaret Cochenour Memorial Hospital. “In addition, we are doing our part to protect the environment contributing to a healthier community.”

A number of energy and infrastructure upgrades were implemented including adding natural gas service to the hospital. This allowed the hospital to convert equipment that was previously powered by fuel oil and liquid propane to natural gas, a more economical option.

The building automation system was also upgraded including an enhanced metering solution to accurately track where energy is being consumed, making it easier for the hospital to evaluate conservation strategies and identify additional efficiency measures.

Other facility upgrades included replacing lighting systems with more energy efficient alternatives; replacing outdoor lighting with LED technology; adding lighting control strategies; installing new natural gas-fired humidifiers and replacing aging exhaust fans.

“Rising utility and operating costs are challenges to any organization, especially hospitals, which need to focus resources on healthcare services,” said Luis Rodrigues, Vice President of Energy Solutions for Honeywell Building Solutions. “The energy retrofit and facility renewal program supports Red Lake’s goal of becoming more energy-efficient and environmentally-conscious for the patients, staff, visitors and the surrounding community in which they serve.”

P. O. Box 5005 / Hwy 105, Red Lake, Ontario POV 2M0
Telephone (807) 727-2231 Fax (807) 727-2923
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TAB 10

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Gold and Natural Gas: building a pipeline to better business in Red Lake

Welcome to Red Lake



Nestled along pristine waterways and amid stately pine trees, the Town of Red Lake is the most north-westerly municipality in Ontario and home to one of the richest gold mining regions in the world.

The half dozen town sites that make up the Municipality of Red Lake have been built historically by mining high grade gold ore in this beautiful wilderness region of northwestern Ontario. Now, a recently completed underground natural gas pipeline is bringing additional economic development opportunities and benefits to the businesses and residents of a district still revered as "the last great gold rush in North America."

As the result of a cooperative partnership involving the private sector and three levels of government, work began on the engineering, design, construction and financing of a 43 kilometre pipeline from a historic mine site along Highway 105 into the Red Lake region. Completed in the fall of 2012, natural gas has become not only a key energy source for area mines owned by Goldcorp, but is also a lower cost, energy alternative for homes and businesses in the municipality which currently rely on electricity, fuel oil or propane.

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“The extension of a natural gas pipeline to businesses within our community has been a phenomenal success”, says Bill Greenway, Economic Development Officer with the Corporation of the Municipality of Red Lake. “Over 75% of our commercial businesses have signed up so far for conversions to natural gas. Many of these same business owners are telling us of the savings they are seeing on their energy bills.”

FedNor, the provincial government, Goldcorp, the Municipality of Red Lake and Union Gas worked closely to make the project a reality. With increased mining activity in the region, natural gas services provide a long-term and sustainable energy alternative for mine operations as well as other significant environmental and economic implications according to Bill Greenway. “Mining operations in the region have addressed their growing needs for more affordable power and our municipality now has the infrastructure to attract and support new business beyond mining”, says Mr. Greenway. “One of the immediate impacts has been in the heating and plumbing sector where two new companies have come to the community to help meet the demand for conversions and equipment installations.”

FedNor’s investment of \$2.7 million supported the engineering, design and construction costs related to establishing the natural gas link to service businesses as well as residences in the community. Today, the pipeline extension project is proving to be the catalyst for community economic and business development that the region’s Mayor was hoping for. “Thanks to FedNor’s support, this project is a win-win situation,” says Phil Vinet, Mayor of Red Lake. “We’re seeing cost savings for local businesses, new jobs being created, plus new opportunities for businesses throughout the region.”



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TAB 11



cutting through complexity

Jurisdictional Review of Natural Gas Distribution System Expansions

March 31, 2015

Prepared for the
Ontario Energy Board

CONFIDENTIAL

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1 Introduction

The Ontario Energy Board (“OEB” or “Board”) retained KPMG LLP (“KPMG”) to provide advisory services to help the Board in determining best practices for natural gas distribution system expansion. The purpose and scope of our research entailed a review of similar and relevant jurisdictions to determine if there are lessons to be learned for rural natural gas expansion, particularly with respect to the onboarding of new franchise areas and new entrants.

1.1 Approach

The jurisdictions assessed herein were selected for further research in collaboration with the OEB following an initial jurisdictional scan encompassing nearly two dozen U.S. states and Canadian provinces. Our research focused primarily on the way regulators approve applications from new entrants, evaluate expansion projects into unfranchised territories and/ or implement other policies to accomplish similar objectives.

This report analyses in detail developments in six jurisdictions to assess the processes used in each to expand natural gas distribution systems into unserved or underserved areas:

Country	Jurisdictions
United States	Alaska
	Connecticut
	Maine
	New York
	North Carolina
Canada	New Brunswick

In undertaking this research and analysis, KPMG relied on information obtained from secondary sources, including reports, presentations, testimony, applications, orders, websites and articles by utilities, regulators, legislatures, industry associations and energy commentators. We have not independently verified the information obtained from these sources and therefore cannot confirm the accuracy of the materials presented. Given that the purpose and scope of this jurisdictional review was to examine policy and processes, we did not undertake quantitative data analysis.

In the course of our work we were able to review only a portion of the large number of materials that are available on this subject. It is possible that we have not selected the most relevant material and that there may be other findings that would be of greater interest. Additional information about developments in a selection of other jurisdictions is included as Appendix 1.

1.2 Report Structure

This report is structured as follows:

- Executive Summary, which highlights main findings.
- Case Studies, with each organized into the following 6 sections:
 - *Case Study Overview* – a one-sentence summary of the case study.
 - *The Problem* – a description of gas supply and demand in the respective jurisdiction.
 - *Proposed Solutions* – a summary of the jurisdiction’s broader policy and regulatory proposals.
 - *Tools Used* – a narrower focus on policy decisions.
 - *Regulatory Issues* – a process-oriented analysis describing regulatory decision-making.

- *Outcomes* – a description of any subsequent developments, if known.
- Observations that elaborate on the Executive Summary.
- Comparative Tables that provide an overview of the jurisdictional review.
- Appendix 1, which presents a high-level summary of relevant findings from the initial jurisdictional scan.
- Appendix 2, which presents a list of 21 discussion questions issued by the New York State Public Service Commission in advance of a technical conference it held on natural gas expansion.
- Appendix 3, which presents a list of 15 discussion questions published by the National Regulatory Research Institute on issues that utility commissions should consider on natural gas expansion.

2 Executive Summary

2.1 Context

Approximately 3.5 million homes and businesses in Ontario have access to natural gas.¹ However less than 20 percent of rural residents do.² Some estimates indicate that there may be 40 communities with populations greater than 500 that could be considered viable candidates for new gas distribution systems.³ As a result, policymakers and regulators have an interest in evaluating potential strategies for expanding natural gas service.

On February 18, 2015, the Ontario Energy Board issued a letter to all applicants and potential applicants with the appropriate financial and technical expertise, giving them the opportunity to propose plans for natural gas distribution system expansion in Ontario. In the letter, the Board said it would hear applicants' requests for regulatory flexibility pertaining to proposed system expansion projects on matters such as:

- The potential use of surcharges to improve project feasibility by reducing the level of upfront capital contribution;
- The potential allowance for recovery of the revenue requirement associated with expansion costs in rates prior to the end of any incentive regulation plan term once the assets are used and useful; and,
- The potential consideration of individual projects with a "Profitability Index"⁴ of less than 0.8 and/or a portfolio of expansion projects with a PI of less than 1.0.

Prior to the Board's February 2015 letter, the Province of Ontario had indicated in its Long-Term Energy Plan and in mandate letters to related ministers a potential for government assistance in facilitating natural gas distribution system expansions.⁵ These proposals included the potential creation of:

- "Natural Gas Access Loans" – totalling \$200 million over 2 years to help communities partner with utilities to extend access to natural gas supplies; and,

¹ This figure includes residential, commercial and industrial consumers. *Source:* Ontario. Ministry of Energy. *Achieving Balance: Ontario's Long-Term Energy Plan*. Toronto: Ministry of Energy, 2013. Web. March 2015.

² The Ontario Federation of Agriculture estimates there are 500,000 rural families and 30,000 farms and small businesses in Ontario that would benefit from access to natural gas. *Sources:* Ontario Federation of Agriculture. "Turning up the Heat for Natural Gas Expansion in Rural Ontario." *News*. Ontario Federation of Agriculture, 2013. Web. March 2015; and Ontario Federation of Agriculture. "Natural Gas Infrastructure." *Issues*. Ontario Federation of Agriculture, 2015. Web. March 2015.

³ Examples include Kincardine, Milverton, Bancroft and Marathon. *Source:* Union Gas. *Ontario's Economic Renaissance Fuelled by Natural Gas*. Union Gas, 2013. Web. March 2015.

⁴ The Profitability Index ("PI") is a net present value calculation that the Ontario Energy Board uses to evaluate whether proposed natural gas distribution expansion projects will shield existing customers from the additional costs of system expansion. A PI of 1.0 indicates that over the life of the portfolio of projects, the additional customers connected to the existing system will pay the entire costs of the expansion. The PI can be evaluated through rates and/or an upfront capital contribution. The PI test specifies that any one individual expansion project within a portfolio must meet a PI of 0.8, which is intended to prevent cross-subsidization within a portfolio. *Source:* Ontario. Ontario Energy Board. E.B.O. 188. *Final Report on Natural Gas Distribution System Expansion and Appendix B Guidelines*. Ontario Energy Board, 30 January 1998. Web. March 2015.

⁵ Ontario. Ministry of Economic Development, Employment and Infrastructure. *Mandate Letter*. Ministry of Economic Development, Employment and Infrastructure, 25 September 2014. Web. March 2015.

- “Natural Gas Economic Development Grants” – in the amount of \$30 million to help fund economic development projects.

These recent initiatives in Ontario make it a timely point to review the experiences of other jurisdictions.

2.2 Challenges of Rural Natural Gas Expansion

There are a number of reasons that could potentially explain why a region remains unserved, why a franchise area does not exist or why new entrants have refrained from entering an otherwise established gas distribution market. These reasons may include:

- Regional transmission pipeline constraints;
- Substantial upfront costs associated with fuel-switching, such as equipment replacement;
- Difficulties in accurately forecasting household conversions, such as in areas where electric baseboard heating must be replaced at high cost;
- Topographical challenges, such as rocky, mountainous, coastal or far-northern terrain;
- Unfavourable local economic conditions, including (but not limited to) low customer density, sub-median per capita income and/ or a declining population;
- Regulatory prohibitions on utility cross-subsidization through rates; and,
- Regulatory economic tests that do not provide the flexibility needed to take a long-term view or manage additions on a portfolio basis.

2.3 Key Findings

- No jurisdiction we evaluated was prepared to deviate significantly from the practice of using an economic test – based on a net present value calculation or similar metric – for determining whether a proposed expansion project should be approved.
- We did not observe an explicit preference in the jurisdictions examined for inviting new entrants, creating new service territories or using municipally-based systems to address a lack of service in rural areas.
- Decision-makers were generally not willing to broadly socialize the costs associated with extending service to areas that did not pass the economic test over the existing natural gas distribution grid and existing natural gas distribution customers.
- There was an emphasis across jurisdictions on identifying and prioritizing industrial, commercial or institutional anchor loads.
- With the exception of North Carolina, where certain refunds/ monies were made available to natural gas distributors from the upstream transportation sector, none of the jurisdictions we examined were willing to impose a surcharge or subsidy on the commodity cost of natural gas to fund system expansions.
- To facilitate expansion efforts, regulators experimented with time-limited, project-specific innovations that demonstrated flexibility with respect to a number of factors.
- With the exception of the major greenfield development in New Brunswick, we did not observe an extensive use of deferral and variance accounts to postpone the recovery of costs associated with natural gas system expansions

3 Case Studies

3.1 Alaska

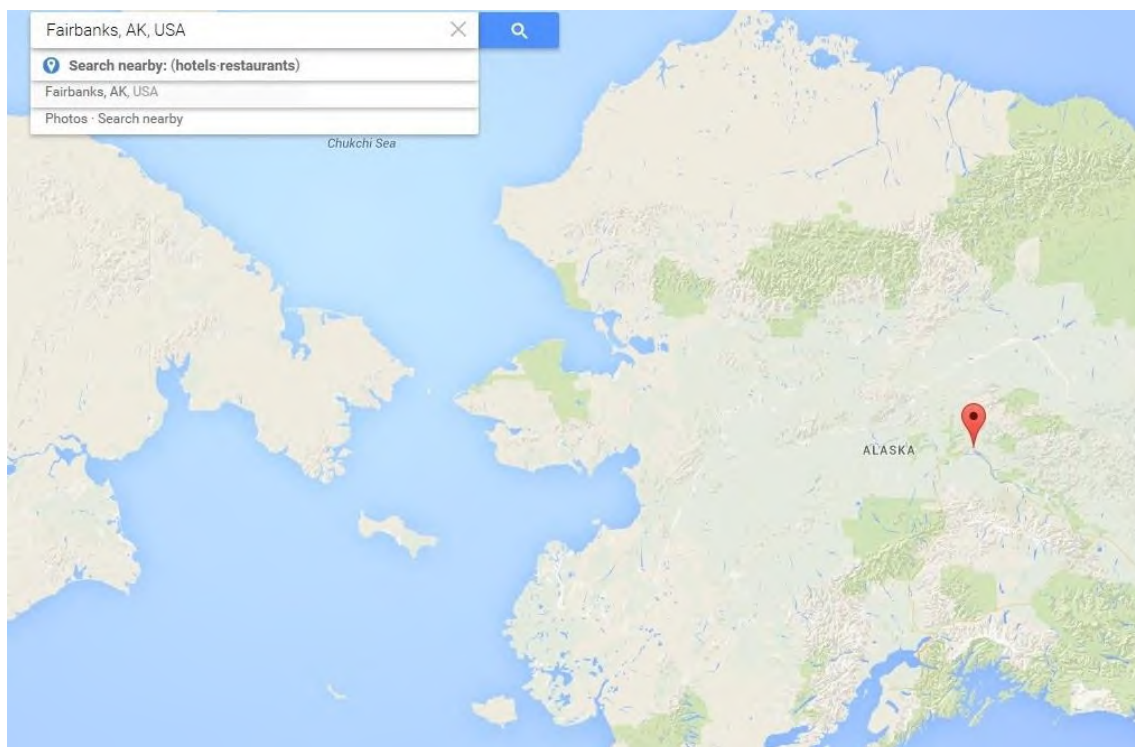
3.1.1 Case Study Overview

This case study examines Alaska's efforts to expand natural gas distribution service to remote communities in the state's interior.

3.1.2 Problem

Among U.S. states, only Texas produces more natural gas than Alaska. Yet despite this abundant local supply, many of the state's residents lack access to natural gas distribution service because the gas is used instead at well sites for oil extraction or to fuel the state's electricity generation.⁶ This is a problem because Alaska's residents consume significant amounts of energy to heat their homes. Only Wyoming and Louisiana consume more energy on a per-capita basis than Alaska.⁷ As a result, household energy bills are "extremely high."⁸ In fact, Fairbanks – the state's second biggest city – has some of the highest residential energy costs of any city in the United States.⁹

Figure 1: Location of Fairbanks, Alaska



Source: Google

⁶ U.S. Energy Information Administration. "Profile Analysis." *State Profile and Energy Estimates: Alaska*. U.S. Department of Energy, 19 June 2014. Web. March 2015.

⁷ Ibid.

⁸ The predominant energy source in Fairbanks is fuel oil. *Source*: Alaska Industrial Development and Export Authority. *Alaska Interior Energy Plan*. Alaska Industrial Development and Export Authority, 22 February 2013. Web. March 2015. Pg. 2.

⁹ Alaska Industrial Development and Export Authority. *Interior Energy Project*. Alaska Industrial Development and Export Authority, 19 February 2015. Web. March 2015.

3.1.3 Proposed Solutions

In 2012, then-Governor Sean Parnell proposed the Interior Energy Plan, which is also commonly referred to as the Interior Energy Project. The Interior Energy Plan was a major proposal to lower energy bills quickly and to improve the region's air quality. As Governor Parnell described it in his 2013 State of the State Address:

"To keep the state of our state strong, let us choose a future of affordable and abundant energy. Despite all our energy sources, energy costs remain a huge burden on Alaskans. That needs to change. That's why we developed the Interior Energy Plan, a strategy that includes low-interest loans, gas storage tax credits and cash for a moveable gas liquefaction plant and distribution system... It will slash energy costs for homes and businesses."¹⁰

The underlying supply components supporting the Interior Energy Plan were:

- Natural gas sourced from Alaska's North Slope, the state's vast oil- and gas-rich area along its northern, Arctic coastline;
- Gas liquefied at a new North Slope LNG plant;
- LNG trucked south to Fairbanks;
- A new regasification and storage plant in Fairbanks; and,
- Local distribution system expansion in the interior communities of Fairbanks and North Pole.

3.1.4 Tools Used

The Interior Energy Plan was implemented using two tools:

- A state financing plan; and,
- The creation of a new municipally-owned utility in the Fairbanks area.

3.1.4.1 State Financing Plan

In 2013, the Alaska State Legislature approved a comprehensive financing package for the Interior Energy Plan.¹¹ Financing came from a few sources:¹²

- \$150 million USD in loans for expanding the local distribution system;
- \$125 million USD in loans for the North Slope LNG plant;
- \$57.5 million USD in grant funding "to directly reduce the cost of LNG";¹³ and,
- \$30 million USD in existing tax credits (\$15 million USD per qualifying LNG storage tank).¹⁴

¹⁰ Governor Sean Parnell. *2013 State of the State Address*. State of Alaska, 16 January 2013. Web. March 2015.

¹¹ Alaska. Legislature. Senate. *An Act Relating to development project financing by the Alaska Industrial Development and Export Authority...* (SB 23) 2013 Reg. Sess. (12 April 2013) *Alaska State Legislature*. Web. March 2015.

¹² These are the figures as they appeared in the Regulatory Commission of Alaska's order granting Interior Alaska Natural Gas Utility a certificate of public convenience and necessity. *Source*: Regulatory Commission of Alaska. Docket: U-13-103. *Order Denying Application of Fairbanks Natural Gas, LLC To Amend Certificate of Public Convenience and Necessity and Granting, With Condition, Application of Interior Alaska Natural Gas Utility for Certificate of Public Convenience and Necessity*. Order No. 19. (Dated and Effective 20 December 2013). Web. March 2015.

¹³ AIDEA, 2013. Pg. 3.

¹⁴ In 2010, Alaska implemented natural gas storage tax credits equal to \$1.50 USD per thousand cubic feet of "working gas" storage capacity, up to the lesser of \$15 million USD or 25 percent of the costs incurred to establish gas storage facility. These credits may be used to offset up to 100 percent of corporate income tax liability. *Sources*: Bill White. "Guide to Alaska natural gas projects." *Alaska Natural Gas Transportation Projects*. Office of the Federal Coordinator, 21 January 2015. Web.

Included in the legislation is an increase in the bonding authority of an existing state agency designed to finance the expansion plans and an interest rate cap of three percent charged to any project financed from the revolving fund established by the financing plan.

3.1.4.2 Creation of New Municipally-Owned Utility

In anticipation of the Interior Energy Plan’s development in and around Fairbanks, two utilities applied to the Regulatory Commission of Alaska (“RCA” or “Commission”) for authorization to supply natural gas service to the new service territory:

- Fairbanks Natural Gas, LLC (“FNG”), wholly owned by Pentex Alaska Natural Gas Company LLC (“Pentex”). Pentex owns three companies in Alaska involved in natural gas transportation and distribution services, but is itself headquartered in Texas and owned by a collection of investment funds headquartered in Minnesota; and,
- Interior Alaska Natural Gas Utility (“IANGU” or “IGU”), a newly formed, public corporation wholly owned by Fairbanks North Star Borough (“FNSB”). FNSB is an upper municipality (the functional equivalent of a county) that includes both the City of Fairbanks and the City of North Pole, which is on the outskirts of Fairbanks.

FNG had served the densely-populated areas of downtown Fairbanks since 1998 and, as of the time of the Interior Energy Plan, had approximately 1,100 customers. Its natural gas is sourced in the form of LNG from Cook Inlet to the south and trucked to Fairbanks where it is vaporized and distributed through FNG’s distribution system. FNG expanded in 1999 and 2005, but subsequent expansion plans were delayed due to uncertainty around future LNG supplies from Cook Inlet. With the prospects of new LNG supplies sourced from Alaska’s North Slope and a new regasification and storage plant in Fairbanks, FNG applied to the RCA to amend its Certificate of Public Convenience and Necessity (“CPCN” or “certificate”) to expand its service territory.

Concurrent to FNG’s filing, IGU was a new entrant that filed for a certificate to service the areas surrounding FNG’s territory. It was formed when the two cities within FNSB (i.e., Fairbanks and North Pole) voted to transfer their utility powers to the Borough. While municipally-owned utilities are exempt from regulation in Alaska, they do need to apply to the Commission for their initial CPCN.¹⁵

For reasons discussed in the next section, the Regulatory Commission of Alaska denied FNG’s application and granted IGU the new franchise and service territory. From our own review of the applications’ details, it appears that the two proposals offered comparable economics but that IGU committed to a more aggressive expansion program and could offer to finance the expansion without the need for a return on equity. The data in the application indicate:

Entity	Customers	Rate Base per Customer	Sales (MCF)	Tariff per MCF
Fairbanks Natural Gas	1,980	\$26,495	3,274,089	\$15.56
Interior Gas Utility	13,366	\$28,535	3,448,977	\$15.45

March 2015; and Alaska Department of Natural Resources. Division of Oil & Gas. “Financial Incentives and Tax Credit Programs.” *Exploration Incentives*. Alaska Department of Natural Resources, 2013. Web. March 2015.

¹⁵ Alaska Stat. § 42.05.711.: Exemptions.

Figure 2: Natural Gas Distribution Areas Territories in Fairbanks, Alaska



Source: Alaska Industrial Development and Export Authority

3.1.5 Regulatory Issues

Alaska Statute 42.05.241 sets out the requirements for when the RCA may grant a certificate. The two conditions are that:

- “The services are required for the convenience and necessity of the public;” and,
- “The applicant is fit, willing and able to provide the utility services applied for.”¹⁶

The Commission had already found in three previous orders – dating to 1997, 2000 and 2005 – that natural gas distribution service satisfied the first condition, both in general terms and in the Fairbanks area specifically. With respect to the second condition, there is a multi-part test, which the Commission evaluated both for FNG’s and IGU’s applications.

The threshold requirements to demonstrate “fitness, willingness and ability,” as described in the RCA’s order granting IGU a certificate, are:

- Sufficient organization;
- Financial backing;
- Technical facilities and equipment, including proposals for engineering and construction of plant to be built;

¹⁶ Alaska Stat. § 42.05.241.: Conditions of issuance.

- Operations expertise; and,
- Management and administrative experience.

The Commission found that FNG failed to demonstrate it had a viable expansion plan for the proposed new area, which resulted in its application to expand its service territory to be denied. Specifically the Commission was skeptical of FNG's ability to guarantee the industrial load that its expansion plan was based upon.

Conversely IGU had advantages in a few categories. In addition to relying on the state financial assistance as part of the Interior Energy Plan, IGU was backed by:

- The resources of the Borough;
- Its ability to raise taxes; and,
- Its ability to issue bonds.

The Commission wrote:

"IANGU has access to intra-agency loans from the FNSB, has access to tax-exempt financing such as revenue and general obligation bonds, has income and property tax exempt status, and has the ability to qualify for state and federal loan and grant programs. IANGU presented testimony that it has an advantage over an investor-owned utility in accessing low cost debt and grant financing."¹⁷

In support of its application, IGU also submitted a six-year build-out plan to achieve 80 percent saturation within the franchise area by 2021, a peer-reviewed design and a commitment to reinvest any profits back into the infrastructure.

As a result, the Commission found that IGU "demonstrated sufficient levels of fitness, willingness and ability... to provide natural gas utility service in the FNSB," while FNG "failed to demonstrate a threshold level of fitness, willingness and ability sufficient for expansion of its service area."¹⁸

The Commission's ruling against FNG, as noted above, came down to the inadequacy of FNG's proposed expansion plan, and not because it lacked sufficient financial backing or technical expertise. The Commission explained:

"We make no negative finding in these proceedings regarding FNG's continued fitness, willingness and ability to provide service in its existing certificated area. We note that there is a significant customer base available for FNG to expand service within its existing certificated area, and we expect FNG to do so as gas becomes available."¹⁹

IGU's certificate came with only one condition. Security of supply was important to the Commission, and IGU is required to maintain a five-day supply of LNG in storage – a condition that also applied to FNG's existing certificate.

3.1.6 Outcomes

IGU's application projected that it would serve:

- 1,403 customers by the end of calendar year 2017; and,

¹⁷ Regulatory Commission of Alaska. *Order No. 19*. Pg. 24.

¹⁸ Ibid. Pg. 27.

¹⁹ Ibid. Pg. 19.

- 13,336 customers by the end of calendar year 2021.

However, there have been two significant developments since the creation of the Interior Alaska Natural Gas Utility:

- As of today, the supply of LNG from the North Slope is in doubt. Due to escalating costs, the private-sector contractor that would have transported LNG to Fairbanks via trucking was unable to proceed with the contract. Alaska ended its formal agreement with the partner company and is currently reviewing options, such as using the state-owned railroad to transport the gas instead.
- To speed the transition to natural gas, the State of Alaska is considering buying Fairbanks Natural Gas through its state economic development agency, the Alaska Industrial Development and Export Authority ("AIDEA"). Due diligence is underway.²⁰

3.2 Connecticut

3.2.1 Case Study Overview

This case study examines Connecticut's recent policy proposals to expand natural gas distribution service to reach the state's rural communities.

3.2.2 Problem

Unlike in neighbouring Massachusetts and Rhode Island where nearly half of all households use natural gas for space heating, less than a third do so in Connecticut.²¹ The state's gas infrastructure currently leaves many rural communities far from transmission and distribution mains, and even in areas where gas mains exist, approximately 216,000 residential and commercial customers²² have not converted – despite the fact their hook-up costs would be covered by LDCs.²³ An additional 89,000 "off-main" customers would require 900 miles of new mains to reach. For these households and businesses, Connecticut's Department of Energy and Environmental Protection estimates it would cost \$1.44 billion USD to provide distribution infrastructure to all of them (broken down as \$512 million USD for service and meters and \$926 million USD for gas main extensions). (These figures imply average costs of \$16,160 per customer for the off-main group.) To add to these costs – for a state with just over 3.5 million people – an additional \$1.16 billion USD would be required for residential or commercial equipment conversion.²⁴

Similar to other states in New England, Connecticut has no in-state sources of natural gas, relying on interstate pipelines for supply instead. This has led to concerns about supply, especially in cold winter months, as the state has been increasing the share of natural gas used for electricity generation.²⁵

²⁰ Dermot Cole. "State agency to purchase Fairbanks natural gas utility." *Alaska Dispatch News*, 28 January 2015. Web. March 2015.

²¹ Connecticut. Department of Energy and Environmental Protection. *2013 Comprehensive Energy Strategy for Connecticut*. Department of Energy and Environmental Protection, 19 February 2013. Web. March 2015.

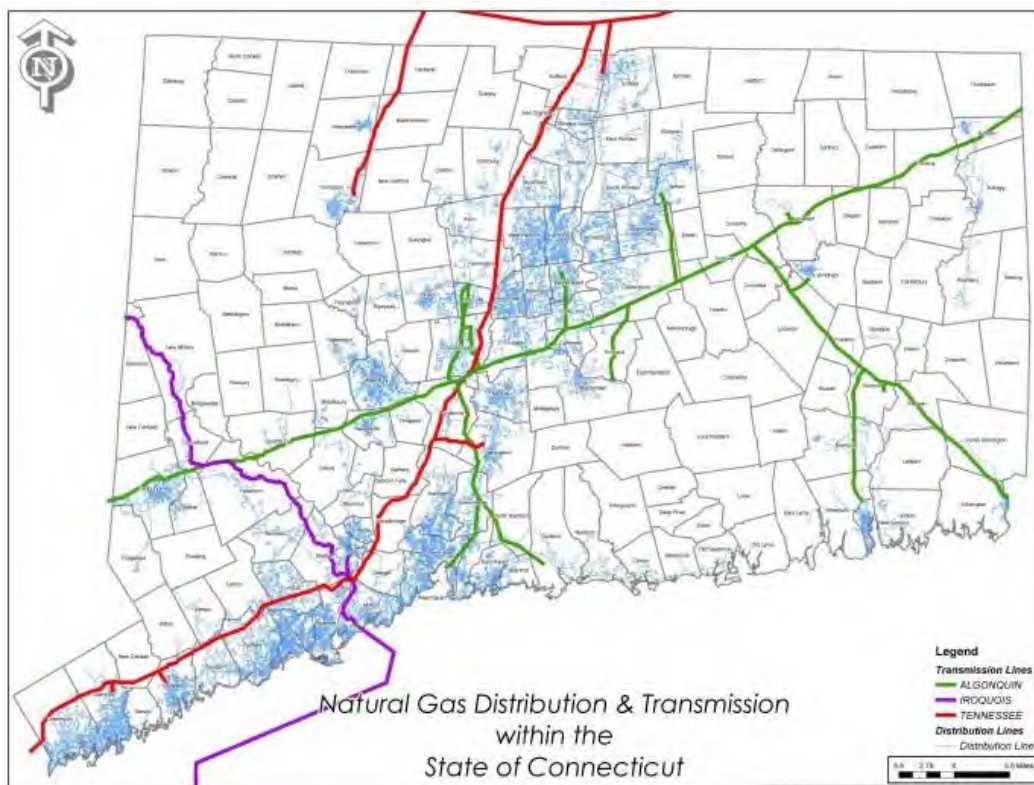
²² Ibid.

²³ Connecticut's three gas LDCs are Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company and Yankee Gas Services Company.

²⁴ All monetary figures attributable to the *Comprehensive Energy Strategy*. Population estimate from United States Census Bureau.

²⁵ U.S. Energy Information Administration. "Profile Analysis." *State Profile and Energy Estimates: Connecticut*. U.S. Department of Energy, 18 December 2013. Web. March 2015.

Figure 3: Connecticut's Natural Gas Infrastructure



Source: 2013 Connecticut Comprehensive Energy Strategy

3.2.3 Proposed Solutions

In 2013, Connecticut's Department of Energy and Environmental Protection ("DEEP") released the *Comprehensive Energy Strategy* ("CES" or "strategy"). While an objective analysis, this document was closely aligned with Governor Dannel P. Malloy's political commitments to lower energy bills and improve the environment. The CES was the result of a broad consultation process. A draft strategy was released months before finalization and subjected to public comment, numerous agency reviews, six technical meetings and five public hearings. As a result, the strategy's proposals can be considered "current thinking" on the natural gas policy in this state.

At over 200 pages, the detailed strategy document proposed a planning horizon out to the year 2050, with a number of changes to energy policy in the following areas:

- Energy efficiency;
- Industrial energy needs;
- Electricity supply including renewable power;
- Natural gas; and,
- Transportation.

The next section focuses on the statutory and regulatory proposal contained in the chapter on natural gas and is best summarized by the following paragraph in the *Comprehensive Energy Strategy's* introductory chapter:

"The Strategy further seeks to align Connecticut's energy future with the emerging opportunity provided by shale gas for a lower-cost, less-polluting and domestically available (and thus more reliable) foundation for society's energy needs. In identifying natural gas as a bridge to a truly sustainable energy future, it puts forward a seven-year game plan for expanding access to natural gas across Connecticut with

a goal of providing nearly 300,000 [additional] Connecticut homes, businesses and other facilities with an energy choice that includes natural gas.”²⁶

In several places throughout the CES, it is emphasized that the state legislature, DEEP, the Public Utilities Regulatory Authority (“PURA”) and other state agencies are to use the strategy’s priorities and proposals to guide future decision making.

3.2.4 Tools Used

This section describes the detailed recommendations outlined in the *Comprehensive Energy Strategy*. While the CES has a planning horizon out to 2050, the natural gas expansion planning horizon was intended to take place over the seven years following the strategy’s release. The most relevant policy proposals to expanding distribution services to unserved and underserved areas are²⁷:

- Establish a planning process for natural gas expansion;
- Raise customer awareness of the opportunities for fuel-switching through marketing;
- Make energy efficiency investments and fuel-switching affordable through financing and incentives for choosing the most energy efficient technology;
- Enact regulatory changes to broaden the reach of financing options that utilities may provide and update Connecticut’s regulatory accounting processes; and,
- Coordinate and streamline permitting and siting processes for building underground infrastructure.

3.2.4.1 Establish a planning process for natural gas expansion

The strategy recommends that Connecticut’s three LDCs be required to submit annual expansion plans that track a number of elements, including:

- **Customer conversion plans and schedules** that outline which customers in their service territory are targeted that year for conversion, sub-divided into a number of categories like on-main and off-main, and residential, commercial and industrial, etc. Further, these plans should target anchor loads and assess their respective economic development potential, as well as target residential areas where customer conversion is likely to be high – such as newer developments or prior expressions of consumer interest;
- **Feasibility analysis** that includes estimated capital budgets, assessment of market conditions (e.g., gas-to-oil spread) and cost/ benefit analysis;
- **Outreach and marketing efforts** to gauge customer awareness;
- **Assessment of pipeline supply capacity** to ensure reliability;
- **Financing mechanisms** that could be leveraged to finance capital and operational expenditures;
- **Cost-reduction strategies** that demonstrate the LDCs have taken into account measures to reduce the cost of expansion (e.g., targeting whole neighbourhoods at once, dedicating specific crews for main extensions, streamlining permitting and siting, etc.); and,
- **Regulatory proposals** that the LDCs recommend for the Public Utilities Regulatory Authority’s consideration, to help each LDC implement its plans.

²⁶ DEEP, 2013. Pg. ii.

²⁷ An additional set of recommendations in the CES were targeted at those Connecticut households and businesses where fuel-switching to natural gas is not considered feasible at this time, in that projected savings under current prices could not be made to cover the costs of conversion/ expansion. Those additional recommendations were primarily aimed at energy efficiency issues, such as more efficient oil and propane furnaces, solar thermal water heating, ground source heat pumps, mandating low-sulfur heating oil, among other proposals.

3.2.4.2 Raise customer awareness of the opportunities for fuel-switching through marketing

The CES estimates that a “robust marketing effort” by Connecticut’s three LDCs would cost approximately \$1.5 million USD to \$2 million USD a year. The strategy proposes that each utility seek to increase customer awareness in its service area about the cost savings from fuel-switching, the importance of planning ahead (as opposed to waiting until a furnace must be replaced) and the ability to reduce individual household costs by aggregating fuel-switching with neighbours or a local anchor load.

3.2.4.3 Make energy efficiency investments and fuel-switching affordable through financing and incentives for choosing the most energy efficient technology

An issue common to the challenge of converting customers to natural gas is the oftentimes high upfront costs of conversions – both to extend service lines to residences and to replace existing, functioning equipment. Even if customers fully understand the benefits of natural gas and would like to convert, they may simply be unable to afford to pay these costs.

The CES puts forward several proposals to address this issue:

- Loan programs for high efficiency heating and domestic hot water systems, delivered through participating banks and credit unions and potentially with state support in the form of a subsidy;
- On-bill financing programs delivered through participating gas companies;
- For particularly high-cost conversions, the strategy calls on LDCs to include in their annual expansion plans proposals on how to offer lower interest financing²⁸ to specific sets of off-main consumers; and,
- Direct incentives (e.g., time-limited tax credits or program spending) to encourage off-main households or businesses to convert.

3.2.4.4 Enact regulatory changes to broaden the reach of financing options utilities may provide and update Connecticut’s regulatory accounting processes

These proposals are discussed in more detail in *Section 3.4.5: Regulatory Issues* below.

3.2.4.5 Coordinate and streamline permitting and siting processes for building underground infrastructure

In 2012, legislators in Connecticut passed a law that, among other things, required municipalities and the Department of Transportation to notify the Public Utilities Regulatory Authority about pending construction projects on public highways so that PURA could in turn notify utilities of opportunities to install underground infrastructure (e.g., gas lines, water mains, sewers, etc.). The strategy calls for LDCs to seek to align their expansion projects along these corridors when possible. According to the CES, installing gas mains at the same time road construction is already underway can lead to savings of 20 percent, for example, by sharing the cost of excavation and paving.

To avoid bottlenecks in the permitting, siting and inspections of future gas expansions – which could be expected during the proposed 7-year build-out period – the strategy proposes a generic approvals process, standardizing the application process and bulk procurement where feasible.

²⁸ The CES does not provide more detail on this proposal, saying instead “Because there is a wide difference in conversion economics and in the assumptions created by various policy underpinnings, it is essential to evaluate expansion options in detail by sub-segment and geographic location as well as under various policy refinements.” DEEP, 2013. Pg. 151.

3.2.5 Regulatory Issues

Connecticut's *Comprehensive Energy Strategy* proposes the following regulatory changes:

- Change the "hurdle rate test" to reduce the upfront customer charge for main extensions;
- Alternative rate riders to assist customers in paying for main extension costs – e.g., contributions in aid of construction ("CIAC") – over time as opposed to an upfront payment;
- Allow greater flexibility when calculating customers' main extension costs; and,
- Establish a mechanism for the timely recovery of capital expenditures made by gas companies.

3.2.5.1 Hurdle Rate Test

Similar to many jurisdictions, Connecticut uses a regulatory mechanism called "the hurdle rate test" to determine whether the costs associated with connecting new customers will be sufficiently covered by the expected future increases in revenue from adding those additional customers. The purpose of this calculation is to ensure gas companies pursue customers that will be cost effective. As of the 2013 strategy, the "payback period" used by PURA to calculate the hurdle rate test ranged from 15 years for one LDC to 20 years for the other two. The CES proposed to extend the payback period to 25 years for all three LDCs, noting that one LDC in Massachusetts is even permitted to use 33 years for residential customers. According to DEEP estimates, this one regulatory adjustment (from 15 years to 25 years) could reduce off-main consumers' CIACs by 40 percent. Similarly, commercial and industrial consumers would see substantial benefits.

3.2.5.2 Alternative Rate Riders

One of the most significant costs of conversion for residents that live far from distribution mains is the upfront contribution in aid of construction. Implementing these charges is also time-consuming and carries a cost for LDCs to administer, as CIACs must be calculated for each individual residence. As an alternative to this approach, the strategy recommends that PURA consider spreading these costs over time by "setting rates generically for customers that require a CIAC payment based on similar characteristics such as usage and distance from the main."²⁹ In this way, similar customers would be pooled together, with CIAC costs potentially spread among a larger group. The CES does not go into detail about how this might be made to work, except to acknowledge that it might require PURA to revise or rescind previous orders.

3.2.5.3 Greater Flexibility Calculating Customers' Main Extension Costs

LDCs in Connecticut are currently permitted to include revenue projections in hurdle rate tests only if there is a firm customer commitment to convert to natural gas. This makes project planning unnecessarily complex, as a project's profitability must be recalculated whenever additional customers sign up or previously committed customers fall through. The strategy recommends providing LDCs with the flexibility to make reasonable projections about future customer conversions and include these revenues in their hurdle rate calculations. As this flexibility would entail a greater element of risk, the effect of this change could be monitored over time and adjusted. The also CES recommends moving toward a portfolio view that allows LDCs to group projects together.

3.2.5.4 Mechanism for Timely Recovery of Capital Expenditures

The CES proposes using a new mechanism for LDCs to recover costs associated with gas main extensions in a timely way without proceeding to a full rate hearing, though there is not much detail in the strategy's text as to what this would entail. Instead, the Public Utilities Regulatory Authority is simply asked to study it further.

²⁹ DEEP, 2013. Pg. 152.

3.2.6 Outcomes

Subsequent to the release of the *Comprehensive Energy Plan*, Connecticut's three gas LDCs submitted to PURA a joint, detailed expansion plan.³⁰

While Connecticut may achieve its goal of providing half the state's residences (and three quarters of commercial and industrial customers) access to natural gas, the other half of the state is, unfortunately, considered to provide "unlikely prospects for conversion," with locations too remote to ever recoup costs from energy bill savings under current assumptions and projections.³¹

3.3 Maine

3.3.1 Case Study Overview

This case study examines Maine's efforts to expand natural gas distribution service to unserved communities in the state's interior Kennebec Valley region and along the Atlantic Coast.

3.3.2 Problem

Very few Maine households have access to natural gas. The population is predominantly rural, and Maine has the lowest population density of any state on the U.S. East Coast. Among U.S. states, Maine ranks 49 out of 50 with respect to the number of homes using natural gas for space heating, with only one out of every twenty residences using it.³² Instead the vast majority of households – 80 percent – use fuel oil.³³

Maine is supply constrained and entirely dependent on imports via pipelines from New Hampshire and Canada. Extremely cold winters can cause shortages and price uncertainty. Most of Maine's natural gas consumption goes toward electricity generation and forestry-related industry.³⁴

3.3.3 Proposed Solutions

In 2012, the Maine State Legislature passed *An Act to Expand the Availability of Natural Gas to Citizens of Maine*, which authorized state bond financing for gas distribution investments. Under this legislation, the Finance Authority of Maine is permitted to issue bonds for gas distribution expansion projects so long as the applicant contributes 25 percent of the expected total project cost.³⁵

In 2013, Governor Paul LePage identified natural gas distribution system expansion as a priority in the annual State of the State Address, committing to "fast-tracked permitting... for all natural gas infrastructure," projecting yearly savings of \$800 USD per household.³⁶

³⁰ Connecticut Public Utilities Regulatory Authority. Docket Number: 13-06-02. *Connecticut's Gas LDCs Joint Natural Gas Infrastructure Expansion Plan*. Public Utilities Regulatory Authority, 14 June 2013. Web. March 2015.

³¹ DEEP, 2013.

³² U.S. Energy Information Administration. "Profile Analysis." *State Profile and Energy Estimates: Maine*. U.S. Department of Energy, 18 December 2013. Web. March 2015.

³³ Lori Valigra. "Will natural gas alleviate Maine's energy woes?" *Mainebiz*, 2 September 2013. Web. March 2015.

³⁴ U.S. EIA, 2013.

³⁵ Maine. Legislature. *An Act to Expand the Availability of Natural Gas to Maine Residents*. (LD 1644) 2012 Reg. Sess. (29 March 2012). *Maine State Legislature*. Web. March 2015.

³⁶ Governor Paul LePage. *2013 State of the State Address*. State of Maine, 5 February 2013. Web. March 2015.

Additionally, Maine law and regulatory precedent allow for a greater degree of utility competition than our research found in other jurisdictions. Specifically:

- A utility that has been previously authorized to provide natural gas service in Maine *does not* need to obtain further regulatory approval to expand into another area – so long as that other area is currently unserved. Maine’s Revised Statutes 35-A §2104 reads: “...a gas utility authorized to furnish service and serving customers within the State is not required to obtain the approval of the commission to serve in any municipality in which no other gas utility is furnishing similar service...”;³⁷ and,
- Maine’s Public Utilities Commission (“MPUC” or “Commission”) has “a longstanding policy in favor of gas utility competition and does not grant exclusive gas franchise territories.” Even if a community *is* served by an existing LDC, the regulator can grant authorization as a second utility under Maine’s Revised Statutes 35-A §2105.³⁸

3.3.4 Tools Used

Natural gas distribution system expansion to unserved areas in Maine has been accomplished recently through the approval – and subsequent expansion – of a new entrant, Summit Natural Gas of Maine (“SNG” or “Summit”). SNG is a subsidiary of Summit Utilities, Inc., a privately-held natural gas transmission and distribution company that operates subsidiaries in Maine, Missouri and Colorado. The company describes its business strategy as “to aggressively seek opportunities to provide natural gas transmission and distribution in areas where natural gas is underutilized.”³⁹

In June 2012, SNG applied to the MPUC for unconditional approval to provide natural gas services. SNG’s proposal was to build transmission and distribution lines servicing 17 communities⁴⁰ in central Maine’s Kennebec Valley, which includes the state capital of Augusta. A handful of industrial facilities – mainly paper mills and a farm – would act as anchor loads, and gas would be supplied via the Maritimes & Northeast Pipeline. Two transmission lines of 12.9 miles and 52.2 miles were proposed as the backbone for local distribution mains and service lines throughout the valley.

The key elements of SNG’s plan were:

- A \$350 million USD investment to create a network to service 15,000 customers during an initial period;
- A 10-year rate plan – with annual reviews and (if necessary) modifications capped at 4 percent of last year’s tariff recovery – that includes an adjustment for return on equity that is below a five-year running average rate;
- A rate of return on equity that is below utility industry standards for the initial years in the tariff plan;
- Rates that include an allowance for the utility to fund construction when a new customer is more than the standard distance from the existing pipeline network;
- “Second utility” status to allow SNG to serve alongside an incumbent utility in Augusta; and,
- An opportunity to fund pipeline expansion and customer conversion rebates using Tax Incentive Financing.

³⁷ Maine Revised Statutes, 35-A §2104: Commission approval for gas companies to furnish service.

³⁸ Summit Natural Gas of Maine, Inc. *Response to Towns of Cumberland, Falmouth and Yarmouth: Natural Gas Pipeline and Utility Service Request for Proposals*. SNG, 25 January 2013. Web. March 2015. Pg. 15.

³⁹ State of Maine Public Utilities Commission. Docket No. 2012-258. *Petition for Authority to Furnish Service as a Gas Utility*. SNG, 1 June 2012. Web. March 2015.

⁴⁰SNG’s service area would comprise: Richmond, Farmingdale, Gardiner, Hallowell, Augusta, Sidney, Belgrade, Waterville, Oakland, Fairfield, Norridgewock, Madison, Skowhegan, China, Albion, Windsor and Winslow.

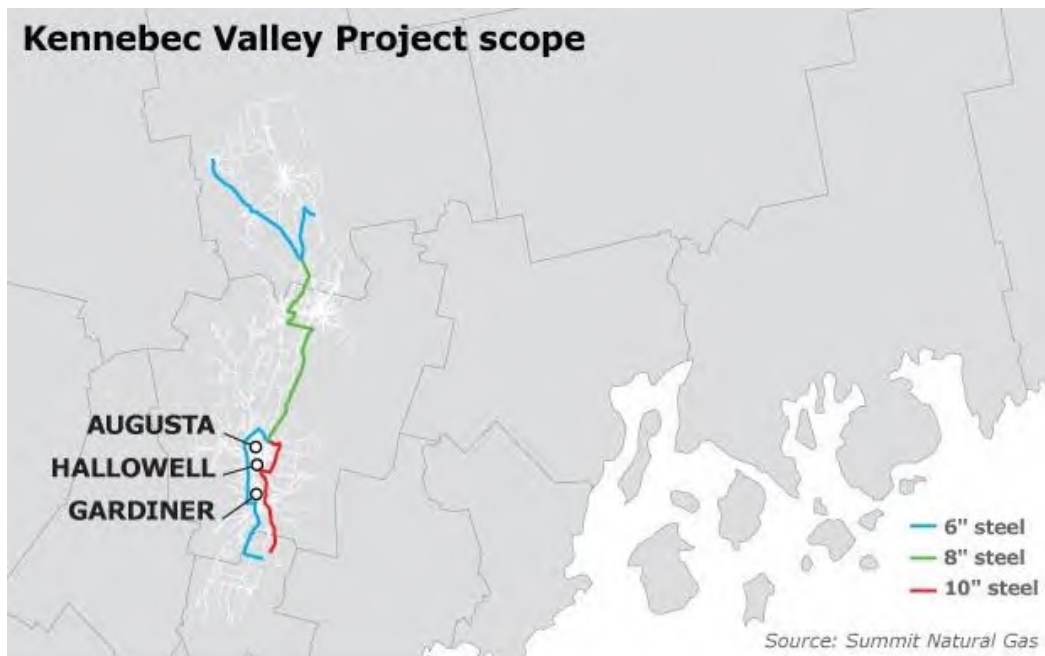
SNG estimated its Kennebec Valley project would cost a total \$350 million USD, with \$240 million USD in the first four years to service 15,000 customers across the 17 communities.⁴¹ The initial funding amount represents a cost of \$16,000 per customer for the initial 15,000 customers cited. Total potential customers in the Kennebec Valley were estimated to be as high as 52,000.

Figure 4: Location of Maine’s Kennebec Valley



Source: Google

Figure 5: Summit Natural Gas’s Kennebec Valley Project



Source: Summit Natural Gas

⁴¹ Summit Natural Gas of Maine. *Presentation: Kennebec Valley Expansion*. SNG, 9 October 2013. Web. March 2015.

3.3.5 Regulatory Issues

In Maine, new applicants must demonstrate the following requirements to obtain authorization to supply natural gas:

- A public need for the service;
- The technical ability to provide the service;
- Adequate financial resources to complete the proposed project; and,
- The ability to provide the service at just and reasonable rates.

Maine has a relatively low bar for demonstrating public need for natural gas utility service – essentially if service is not already provided in a given area then public need is presumed. The other three issues require more substantiation.

Demonstrating SNG’s technical ability was straightforward. By the time of expanding into Maine, Summit Utilities had already completed 20 similar projects in Colorado and Missouri over the prior 15 years, serving nearly 35,000 residential, commercial and industrial customers.

With respect to financial resources, the Commission described its economic test as follows:

“A finding of financial capability for purposes of awarding conditional authority is a threshold determination, not a conclusion based on a detailed project and rate analysis. A threshold finding helps assure the public that the entity proposing to become a public utility has a reasonable chance of bringing its project to fruition, but not that it is certain to do so.”⁴²

The Commission further explained that:

“Because the entities and projects presented to us vary, so do our threshold findings, as each case is somewhat unique. We look for characteristics such as adequate business sophistication lending an understanding of how to obtain adequate funding for the project it proposes to build, as well as a high level assessment of the resources it has garnered to date for that endeavor.”⁴³

As a newly-formed subsidiary, Summit Natural Gas of Maine did not have audited financials available for the Commission’s review. Instead the MPUC took into consideration the fitness of SNG’s parent company, Summit Utilities, which was wholly owned by the JP Morgan Infrastructure Investment Fund. At the time, the Fund held more than \$3 billion USD of equity investments. In a subsequent stipulation filed before the granting of unconditional authority, SNG also presented many details about its financial protections with information relating to its dividend payout ratio, level of equity capitalization, separation of credit facilities from affiliates, money pool arrangements, credit approval requirements and treatment of books and records.

With respect to rates, SNG presented to the MPUC a proposed 10-year rate plan. SNG credits its pricing model as a key to expansion because it includes, in effect, an on-bill loan that helps to bridge the gap between upfront costs of conversion and the subsequent annual bill savings from gas as a cheaper fuel source:

“SNG has a very different pricing model that enables expansion to serve customers. By including the cost of expansion – the [contribution in aid of construction] charges

⁴² State of Maine Public Utilities Commission. Docket No. 2012-258. *Order Granting Conditional Authority and Denying Motion to Dismiss*. MPUC, 17 October 2012. Web. March 2015. Pg. 6.

⁴³ *Ibid.*

– within our rates, we are able to expand to serve customers without having those customers pay separately for construction of lines to serve them. Moreover, our rates include a generous allowance – actual cash rebates – to help customers pay for the cost of converting to natural gas. Our model is unique, but it is the basis for our high penetration rates. Other utilities may have lower rates, but their rates do not permit expansion. A low rate is of no value to customers who cannot obtain gas service. SNG’s rate structure is geared toward getting lines built to serve customers. With respect to commercial customers, SNG does not provide conversion rebates.”⁴⁴

The Commission found that SNG’s proposed rate plan was similar to ones it had approved previously and contained the right balance of ratepayer and shareholder protections. It is worth noting the MPUC did observe:

“Although SNG Maine’s average distribution rates for all classes are higher than rates currently charged by other Maine gas utilities, SNG Maine will offer a lower cost alternative compared to other fuels, most notably heating oil and propane. In addition, SNG Maine will provide up-front financial incentives to customers to help defray the costs to convert to natural gas.”⁴⁵

The Commission acknowledged that flexibility was necessary to facilitate expansion:

“We observe that where, as here, the utility is seeking customers who are in no sense ‘captives’ of the utility – since virtually all can satisfy their energy needs using other fuels but will reduce their energy costs by adding natural gas as a resource – it makes little sense to apply all the traditional metrics for establishing that rates are ‘just and reasonable.’ Thus in this case we conclude that we can approve a rate plan for SNG Maine that would likely, for a genuinely ‘monopoly’ provider, result in rates that would either qualify as excessive or insufficiently compensatory relative to costs. We will, of course, be vigilant to ensure that customers who take service from SNG Maine are informed of the rate plan and the manner in which rates under the plan can change. As time progresses, alternative equipment ages (and even becomes inoperative) and customers become more dependent and limited in their energy options, the more traditional attributes of monopoly regulation may become more appropriate.”⁴⁶

In January 2013, the MPUC granted unconditional authority to SNG Maine to supply natural gas utility service to 17 municipalities in the Kennebec Valley.

3.3.6 Outcomes

Development has been slower than SNG projected. Since 2013, Summit has delivered natural gas distribution service to only 3,000 customers in 12 communities.⁴⁷ These customers are split between the Kennebec Valley Project and a second expansion project on the coast, which SNG announced shortly after it received approval to supply natural gas in Maine from the MPUC.⁴⁸

⁴⁴ SNG, 25 January 2013. Pg. 23.

⁴⁵ State of Maine Public Utilities Commission. Docket No. 2012-258. *Order Approving Stipulation*. MPUC, 29 January 2013. Web. March 2015. Pg. 11.

⁴⁶ Ibid. Pg. 12.

⁴⁷ Summit Natural Gas of Maine. *Summit Natural Gas of Maine Announces 2015 Construction Plan*. PR Newswire. SNG, 25 February 2015. Web. March 2015.

⁴⁸ Tux Turkel. “For Summit Natural Gas, the path hasn’t been easy.” *Portland Press Herald*. 19 March 2015. Web. March 2015.

In March 2013, SNG won a competitive bidding process held by the Maine coastal communities of Cumberland, Falmouth and Yarmouth, which are located just north of Maine's most populous city, Portland. The three Portland suburbs issued a Request for Proposals to design, construct and operate a local distribution system in the three communities. Two of Maine's utilities submitted bids – Maine Natural Gas and Summit Natural Gas of Maine – while a third, Unitil, declined to submit a bid, choosing instead to focus on its existing areas.

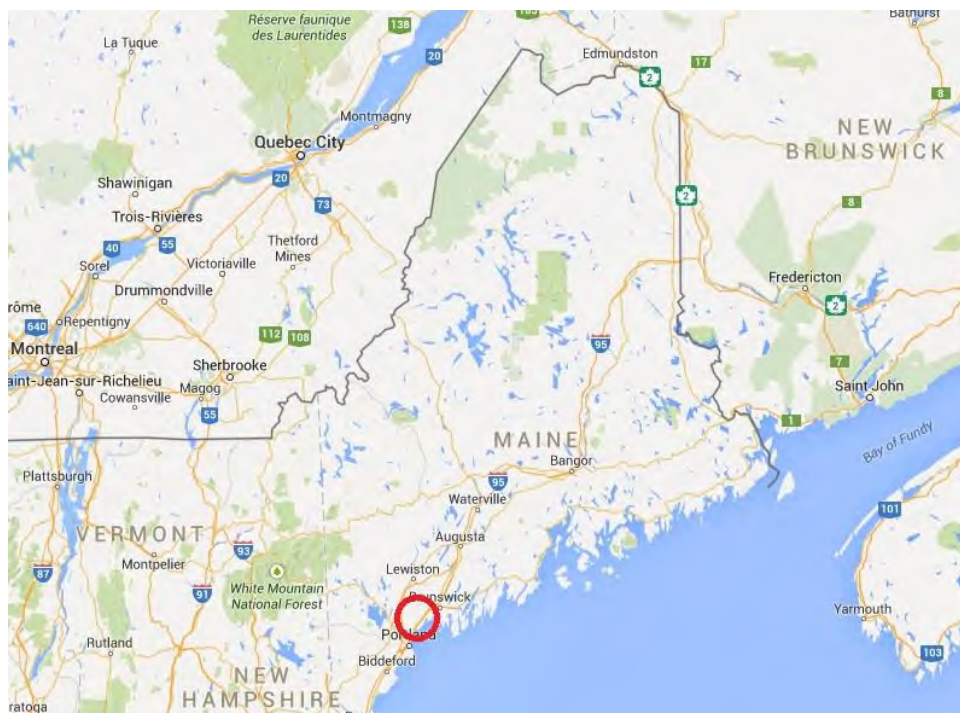
Evaluation criteria were evenly split between three items⁴⁹:

- Saturation plan;
- Pricing structure, capacity, schedule and related considerations; and,
- Previous experience in similar communities, with marketing/ saturation, safety, customer service, reliability, pricing, public outreach and similar concerns.

The communities cited SNG's "experience, saturation commitment and pricing" as the reason for its selection.⁵⁰ SNG proposed to invest \$72.5 million USD to provide local distribution service, targeting nearly 8,000 customers over five years.⁵¹ This investment was in addition to its Kennebec Valley Project. On a per customer basis, projected costs are just over \$9,000 per customer, somewhat less than for the initial expansion noted above.

Currently, Summit's 2015 construction plans aim to lay mainline pipes to 10,000 homes and businesses in both central Maine and the coast.

Figure 6: Location of Cumberland, Falmouth and Yarmouth, Maine



Source: Google

⁴⁹ Maine. Town of Cumberland. Item 12-177. "Request for Proposals: Natural Gas Distribution Pipeline & Utility Service." *Towns of Cumberland, Falmouth and Yarmouth*. Town of Cumberland, 12 October 2012. Web. March 2015.

⁵⁰ Maine. Town of Falmouth. "Information." *Natural Gas Project*. *FalmouthMe.org*. Web. March 2015.

⁵¹ Maine. Town of Falmouth. *Natural Gas Distribution Expansion Project Update*. Falmouth, December 2013. Web. March 2015.

Figure 7: Cumberland, Falmouth, Yarmouth Expansion Project



SOURCE: Summit Natural Gas

STAFF GRAPHIC | MICHAEL FISHER

Source: Summit Natural Gas and *The Portland Press Herald*

3.4 New York

3.4.1 Case Study Overview

This case study examines New York's efforts to expand natural gas distribution service to upstate communities, with an example of a recent expansion.

3.4.2 The Problem

More than half of New York residences use gas for space heating, yet there are still well over one million households within existing service territories with no access to natural gas. This figure breaks down to approximately 550,000 residences within 100 feet from an existing gas main and 580,000 beyond that distance.⁵² Furthermore, despite New York's high saturation rate, there are still unfranchised territories considered too expensive to expand into due to remote, rocky or mountainous terrain.

Instead of ample in-state production, New York has been primarily supplied with natural gas from major pipelines extending from the U.S. Gulf Coast and Canada, with interstate pipelines extending beyond into New England.⁵³ More recently, significant shale production in Pennsylvania has led to

⁵² U.S. Energy Information Administration. "Profile Analysis." *State Profile and Energy Estimates: New York*. U.S. Department of Energy, 18 December 2013. Web. March 2015; and New York State Public Service Commission. Case 12-G-0297. "Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service." *Order Instituting Proceeding and Establishing Further Procedures*. New York Public Service Commission, 30 November 2012. Web. March 2015.

⁵³ U.S. Energy Information Agency, 2013.

additional pipeline capacity from both existing infrastructure and planned expansions. New York, too, has major shale gas deposits. However the state became the first in the U.S. to officially ban hydraulic fracturing in December 2014, though a temporary ban had been in place for 6 years prior.⁵⁴

3.4.3 Proposed Solutions

On November 15, 2012, New York released a 116-page, long-term energy strategy entitled *The New York Energy Highway Blueprint* ("Blueprint").⁵⁵ The Blueprint was officially issued by the Governor's New York Energy Highway Task Force and based on a comprehensive consultation process. The Blueprint's 13 action items predominantly related to electricity policy (e.g., renewable power generation, smart grid technologies, retiring old power plants, etc.), but natural gas was also included.

The most relevant recommendation to natural gas distribution expansion was an action item labelled "Accelerate investments in natural gas distribution to reduce costs to consumers and promote reliability, safety, and emission reductions." According to the Blueprint, New York's gas LDCs have been investing significantly in utility infrastructure – \$5 billion USD in natural gas infrastructure over the prior five years and projected to invest another \$5 billion USD in the subsequent five years, covering both equipment replacement and system expansion to accommodate load growth.⁵⁶

Coming out of the Blueprint was the direction to further examine natural gas expansion policies. This task was assigned to the New York State Public Service Commission ("PSC" or "Commission"). In response, the Commission instituted a proceeding to examine existing state policies, which included a technical conference that took place on January 9, 2013 with 13 presentations from LDCs.

The 16-page order instituting this proceeding provides considerable insight into the Commission's thinking and priorities. The order highlights that over one million people heat with fuels other than natural gas, despite the fact that New York already has 19 regulated gas utilities and considerable existing gas infrastructure.⁵⁷

Echoing the Blueprint, the Commission lays out the environmental, economic and household benefits of switching to natural gas and goes into more detail about the types of specific regulatory issues it is interested in examining further. In particular, the Commission points out that while current statutory and regulatory requirements related to natural gas expansion policy permit some flexibility, "only rarely, however, have utilities sought to employ such flexibility."⁵⁸

In advance of the technical conference, the PSC published a lengthy and detailed list of discussion questions indicating the topics it was interested in exploring. Among the issues to be considered at the technical conference:

- Barriers to Extension and Expansion of Natural Gas Facilities;
- Rate and Ratepayer Considerations;
- Economic Development;
- Public/ Private Partnerships;
- Environmental Impact; and,

⁵⁴ Thomas Kaplan. "Citing Health Risks, Cuomo Bans Fracking in New York State." *New York Times*, 17 December 2014. Web. March 2015.

⁵⁵ New York. New York Energy Highway Task Force. *New York Energy Highway Blueprint*. New York Energy Highway Task Force, 15 November 2012.

⁵⁶ Ibid. Pg. 55.

⁵⁷ For a complete list of the natural gas utilities regulated by the New York State Public Service Commission, please visit: <http://www.dps.ny.gov/>

⁵⁸ New York State Public Service Commission, 2012. Pg. 7.

■ Planning.

The full list of questions is attached as Appendix 2.

3.4.4 Tools Used

Even though the Commission held the technical conference on the topic of natural gas expansion policy – and posted the 13 LDC presentations⁵⁹ to its Department of Public Service website – the PSC did not issue a summary report with recommendations to policymakers, which it had initially set out to do.⁶⁰ Instead, the Commission decided it was more appropriate to deal with the specifics of natural gas expansion policy during future rate cases, applications for certificates of public convenience and necessity, etc. As a result, the next section of this case study will describe the process used by the Commission in advance of one of its orders granting a certificate to a utility to expand into a new service territory.

Last year, New York State Electric & Gas Corporation (“NYSEG”) was granted an amended certificate to exercise a new franchise, expanding into a neighbouring unserved territory far upstate. The Commission’s decision to deviate from established expansion policies to provide more flexibility around the expansion project’s development period, as well as to require more attention to informing potential new customers of expansion, is illustrative. Specifically, the PSC adopted a ten-year development period for the expansion of gas service, as opposed to the established development period of five years.

3.4.5 Regulatory Issues

In New York, gas utility expansions or new entrants require both a franchise agreement with the locality it seeks to service and a certificate of public convenience and necessity authorizing franchise rights, as prescribed in Public Service Law Section 68:

“In making such a determination, the commission shall consider the economic feasibility of the corporation, the corporation's ability to finance improvements of a gas plant or electric plant, render safe, adequate and reliable service, and provide just and reasonable rates, and whether issuance of a certificate is in the public interest.”⁶¹

The Public Service Commission interprets these requirements to mean that expansion projects must be economic for ratepayers⁶² in order to be afforded normal rate treatment, and its policy for

⁵⁹ New York State Public Service Commission. Case 12-G-0297. *Natural Gas Expansion – Presentations from the Jan. 9, 2013 Technical Conference*. New York Public Service Commission, 2013. Web. March 2015.

⁶⁰ The order instituting the proceeding had said, “Upon completion of the Technical Conference, Staff will provide a report to the Commission along with any recommendations it may develop” (page 9). Similarly, the Blueprint listed as an initiative, “By the end of 2012, [Department of Public Service] to issue notice on natural gas expansion policies” (page 57).

⁶¹ NY Pub Serv L § 68 (2012): Certificate of public convenience and necessity.

⁶² New York State Public Service Commission. Case 12-G-0499. “Petition of New York State Electric & Gas Corporation to Amend its Certificate of Public Convenience and Necessity and to Exercise a Gas Franchise in the Town of Plattsburgh, Clinton County, New York.” *Order Amending Certificate of Public Convenience and Necessity and Requiring System Improvements*. New York Public Service Commission, 29 July 2014. Web. March 2015. Pg. 12-13.

determining whether expansion projects would unfairly burden existing ratepayers has been in place since 1989.⁶³ The key elements of that policy include⁶⁴:

- Assessment of franchise proposal over a five-year development period;
- The requirement to earn the utility's Commission-permitted rate of return in the new franchise area by the end of the five-year development period;
- The ability of the utility to levy a surcharge on all customers in the new franchise area during the five-year development period, if the rate of return at the end of that period is projected to be less than the utility's Commission-permitted rate of return; and,
- If the utility levies a surcharge it must be limited solely to what is needed to recover the estimated shortfall that would exist at the end of the five-year development period.

The rate of return test is applied to profitability at the end of the development period as an annual calculation. With respect to revenue deficiency, the expected deficiency (*ex ante*) is collected through a surcharge, which may be the same as the contribution in aid of construction surcharge. It is expected to compensate the utility for the losses in the early years. For broader rate-making purposes (involving the utility as a whole), the revenues from the surcharge are excluded from revenue deficiency estimates. As long as the expansion proceeds as projected, the utility would be kept whole. There is a possibility that the actual deficiency (*ex post*) is different from the *ex ante* level – for example, if expansion was slower than anticipated or costs were higher. In that case, there is a possibility that the actual deficiency will be larger than anticipated. It is not clear from the 1989 policy statement whether the utility is at risk or if the surcharge could be continued beyond the development period to keep the utility whole.

3.4.5.1 New York State Electric & Gas Corporation Expansion

NYSEG provides electricity and natural gas services to customers across New England, including 40 percent of upstate New York.⁶⁵ In 2012 it proposed its largest distribution system expansion project in 15 years⁶⁶ by seeking to expand its natural gas franchise in the far north-eastern part of the state to include a municipal-wide franchise⁶⁷ in the Town of Plattsburgh, a rural, agricultural and sparsely-populated area it had long bordered since the time it started providing service to the neighbouring community of City of Plattsburgh.

⁶³ New York State Public Service Commission. Case 89-G-078. *Policy for Rate Treatment of Gas Service Expansion into New Franchise Areas*. New York Public Service Commission, 11 December 1989. Web. March 2015.

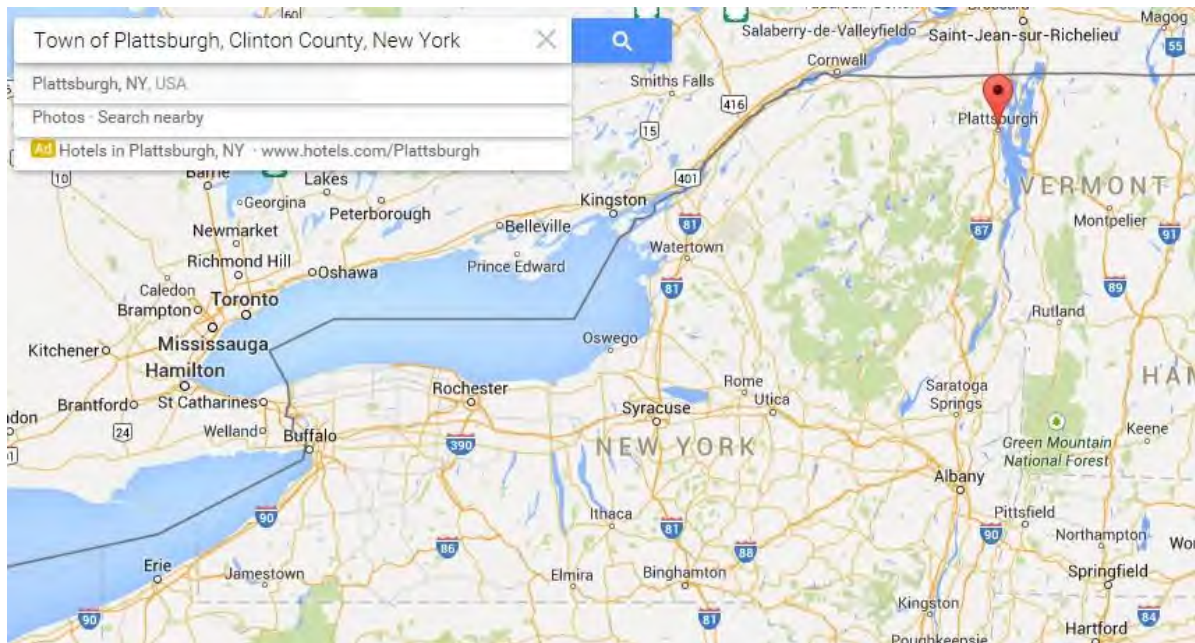
⁶⁴ Paraphrased using the original policy statement (1989) and subsequent Commission descriptions in orders from 2012 and 2014.

⁶⁵ New York State Electric & Gas Corporation. "Our Company: Service Area." *NYSEG.com*. NYSEG, 2015. Web. March 2015.

⁶⁶ Staci DaSilva. "NYSEG Announces Major Gas Line Expansion In Plattsburgh." *My Champlain Valley*, 22 October 2014. Web. March 2015.

⁶⁷ NYSEG had distributed gas to some of the Town's residences along major roadways bordering the City of Plattsburgh but did not have a franchise to distribute to the rural areas.

Figure 8: Location of Town of Plattsburgh, New York



Source: Google

NYSEG's application for a new franchise area was broadly supported by the Town, the local chamber of commerce and the economic development corporation. As part of its petition, NYSEG asked for expedited approval to service an anchor customer (Nova Bus), which the Commission quickly granted for its potential economic benefits and the company's agreement to the required surcharges. With a potential new customer base of 1,200 and initial surveys indicating nearly three-quarters of respondents saying they would convert, the PSC's approval for the rest of the application appeared straightforward.

However the proceeding lasted from November 2012 to July 2014 due to a lengthy back-and-forth between NYSEG and the Commission's staff around feasibility studies, models and build-out plans and multiple iterations thereof. A breakthrough occurred when NYSEG submitted, at the Commission's request, a ten-year development period (twice as long as the one envisioned by the Commission's 1989 policy statement). The significance of the longer development period is that it is the period of time over which rate surcharges can be collected. As a result, the longer development period "significantly reduced estimated monthly CIAC surcharges to customers."⁶⁸ After Commission staff further modified build-out plans in consultation with Town of Plattsburgh officials, a workable solution was agreed upon.

The Commission found that a ten-year development period was justified in light of:

- Current natural gas prices;
- Population density of potential customers; and,
- Significant reductions in monthly CIAC surcharge bill impacts.⁶⁹

Taken together, these elements balanced the need to meet the utility's Commission-permitted rate of return by the end of the development period while still resulting in rates competitive enough that

⁶⁸ New York State Public Service Commission, 2014. Pg. 7.

⁶⁹ The surcharge rate (\$0.282 per therm) equates to \$300 a year for the average residential customer. Even accounting for this amount, customers could save \$1,400 annually compared oil or \$2,200 annually compared to propane. Source: New York State Public Service Commission, 2014, and DaSilva, 2014.

would encourage fuel-switching. In the Commission’s conclusion to the order, it explained that the benefits of this approach included:

“...the economic benefits of increased development in Plattsburgh due to the construction of this project and the expected continued availability of gas as a lower cost heating fuel. Increasing the availability of natural gas to the community may also have the added benefit of business attraction, retention, and expansion.”⁷⁰

Similar to North Carolina’s focus on tracking interest from potential customers, the New York Public Service Commission required NYSEG to keep a record of any potential customer’s interest in receiving gas service. The Commission explicitly laid out the types of required information:⁷¹

- The date a customer inquired;
- Their address;
- What documents NYSEG provided to the customer, if any; and,
- How the inquiry or request was finally resolved.

3.4.6 Outcomes

By 2017, 70 percent of residents in the Town of Plattsburgh are expected to have access to natural gas.⁷²

At the time of this writing, Leatherstocking Gas Company – a new entrant looking to service communities in northern Pennsylvania and southern New York – filed for a new franchise with the Public Service Commission.⁷³

3.5 North Carolina

3.5.1 Case Study Overview

This case study examines North Carolina’s efforts to expand natural gas distribution service to a significant portion of the state over the past 25 years.

3.5.2 Problem

In 1989, North Carolina began a state-wide push to expand natural gas distribution service. At the time, the North Carolina Utilities Commission (“NCUC” or “Commission”) had identified 38 counties out of 100 with no gas service or only minimal service availability. 20 of those 38 counties were located in unfranchised territories of the state.⁷⁴

⁷⁰ Ibid. Pg. 34.

⁷¹ New York Public Service Commission, 2014, page 31.

⁷² DaSilva, 2014.

⁷³ Leatherstocking Gas Company, LLC. Case numbers 15-G-0098 and 15-G-0099 *Verified Petition*. Public Service Commission, 20 February 2015. Web. March 2015.

⁷⁴ North Carolina Utilities Commission. “Analysis and Summary of Expansion Plans of North Carolina Natural Gas Utilities and the Status of Natural Gas Service in North Carolina.” *Report of the Public Staff North Carolina Utilities Commission to the Joint Legislative Commission on Governmental Operations*. NCUC, 24 April 2012. Web. March 2015.

3.5.3 Proposed Solutions

North Carolina enacted 3 key pieces of legislation to promote the expansion of natural gas distribution service:

- *The Natural Gas Planning Act, 1989*,⁷⁵
- *The Natural Gas Expansion/ Cost Act, 1991*;⁷⁶
- *The Clean Water and Natural Gas Critical Needs Bond Act, 1998*.⁷⁷

3.5.3.1 *The Natural Gas Planning Act, 1989*

North Carolina has four private-sector LDCs and eight municipal gas systems.⁷⁸ *The Natural Gas Planning Act* requires each LDC to file biennial reports with the NCUC on the status of expansion projects within their respective franchise territories. The legislation was later amended to apply only to LDCs with unserved areas within their franchised service territories.

Upon receiving the LDCs' reports, the NCUC compiles and summarizes the information and submits it to legislative committees. LDCs are required to report on the following items:

- Inquiries for natural gas service received from potential large users;
- The status of expansion projects previously reported to the Commission; and,
- Plans for potential expansion projects.

As an example, most recently the largest LDC in North Carolina – Piedmont Natural Gas Company – stated it had received 97 inquiries from large commercial and industrial customers about potential gas service:⁷⁹

- 11 were successful (new customers were added as a result of those inquiries);
- 12 were progressing;
- 32 were unsuccessful or not feasible (did not provide gas to the customer); and,
- 42 were still pending (either waiting for data, being evaluated, or halted progress).

⁷⁵ *That Natural Gas Planning Act* is the short title for the bill. Source: North Carolina. Legislature. House. *An Act to Require Natural Gas Local Distribution Companies to Report Plans for Providing Natural Gas Service in Unserved Areas to the Utilities Commission and to Require the Utilities Commission to Report on Expansion of Natural Gas Service to the Joint Legislative Utility Review Committee.* (HB 970) 1989 Session. (31 March 1989) *General Assembly of North Carolina.* Web. March 2015. Note: This law was later amended to require reporting to the Joint Legislative Commission on Governmental Operations.

⁷⁶ *The Natural Gas Expansion/ Cost Act* is the short title for the bill. Source: North Carolina. Legislature. House. *An Act to Facilitate the Construction of Facilities In and the Extension of Natural Gas Service To Unserved Areas and To Revise the Procedures for Gas Cost Adjustments for Natural Gas Local Distribution Companies.* (HB 1039) 1991 Session. (8 July 1991) *General Assembly of North Carolina.* Web. March 2015.

⁷⁷ *The Clean Water and Natural Gas Critical Needs Bond Act* is the short title for the bill. Source: North Carolina. Legislature. House. *An Act to Authorize the Issuance of General Obligation Bonds of the State, Subject to a Vote of the Qualified Voters of the State, to Address Statewide Critical Infrastructure Needs by Providing Funds (1) For Grants and Loans to Local Government Units for Water Supply Systems, Wastewater Collection Systems, Wastewater Treatment Works, and Water Conservation and Water Reuse Projects and (2) For Grants, Loans, or Other Financing to Public or Private Entities for Construction of Natural Gas Facilities.* (SB 1354) 1997 Session. (9 September 1998) *General Assembly of North Carolina.* Web. March 2015.

⁷⁸ The four private-sector LDCs are Piedmont Natural Gas Company, Inc.; Public Service Company of North Carolina, Inc., doing business as PSNC Energy; Frontier Natural Gas Company, LLC; and Toccoa Natural Gas. The eight municipal systems are Greenville, Rocky Mount, Wilson, Shelby, Bessemer City, Lexington, Monroe, and Kings Mountain. Piedmont and PSNC Energy cover the vast majority of North Carolina's territory.

⁷⁹ North Carolina Utilities Commission. "The Status and Expansion of Natural Gas Service within the State." *Report of the North Carolina Utilities Commission to the Joint Legislative Commission on Governmental Operations.* NCUC, 28 April 2014. Web. March 2015.

3.5.3.2 *The Natural Gas Expansion/ Cost Act, 1991*

The initial expansion reports filed under *The Natural Gas Planning Act* indicated that “the extension of natural gas service in some areas of the State may not be economically feasible with traditional funding methods.”⁸⁰ In response, state lawmakers passed *The Natural Gas Expansion/ Cost Act*, which authorized “the creation of an expansion fund for each natural gas local distribution company to be administered under the North Carolina Utilities Commission.”⁸¹

This Act enables the Commission, following a hearing, to order LDCs to create “a special natural gas expansion fund” to be supervised and administered by the Commission. The legislation implementing the expansion fund included two specific and one non-specific funding sources:

- Expansion surcharges applied to the bills of all customers of the local distribution company;
- Refunds received – from gas and transportation service suppliers – by local distribution companies as a result of decisions made by the Federal Energy Regulatory Commission, the federal government’s regulatory body in the United States (comparable to the National Energy Board); and,
- Other funding sources approved by the North Carolina Utilities Commission.

However despite these three options, only supplier refunds and the interest associated with those refunds have been used so far. Changes to U.S. federal legislation and regulation in the years since *The Natural Gas Expansion/ Cost Act* may limit its applicability today.⁸²

3.5.3.3 *The Clean Water and Natural Gas Critical Needs Bond Act, 1998*

By 1998, the North Carolina General Assembly found that “While the 1991 legislation has been successful in providing some natural gas service to previously unserved areas of the State, that legislation has not been sufficient to facilitate the extension of service that is necessary and in the public interest, and there are still counties with no gas service or virtually no gas service.”⁸³

The Clean Water and Natural Gas Critical Needs Bond Act authorized the issuance of \$200 million USD in North Carolina State general obligation bonds “to provide grants, loans, or other financing to natural gas local distribution companies, persons seeking natural gas distribution franchises, State or local government agencies, or other entities for construction of natural gas facilities.”⁸⁴ Section 5 of the Act outlined what the funding could be used for, including (but not limited to) the costs of:

- Pipelines;
- Compressors;
- Interests in real property; and,
- Related equipment for the delivery of natural gas.

3.5.4 Tools Used

All three pieces of legislation noted above have been used. Overall, nearly \$510 million USD has been invested to expand the availability of natural gas to North Carolina’s unserved and underserved

⁸⁰ Quoted from the preamble of *The Natural Gas Expansion/ Cost Act, 1991*.

⁸¹ Ibid.

⁸² In the context of the legislation, “suppliers” meant interstate natural gas pipelines and equivalent entities that were subject to rate regulation. The North Carolina legislation predates the implementation of subsequent reforms (e.g., 1992 Energy Policy Act). Today most gas is either sold under market-based rate authority or in a newer rate-making environment where refunds occur far less frequently.

⁸³ Quoted from *The Clean Water and Natural Gas Critical Needs Bond Act, 1998*.

⁸⁴ Ibid. Section 2(b).

areas. Of this total amount, \$200 million USD was provided by natural gas bonds and \$115 million USD by LDC expansion funds.⁸⁵ The remaining \$195 million USD was provided primarily by LDC investors. Frequent and detailed biennial reports showed lawmakers and regulators where state, LDC and investor funds were being spent on expansion projects.

3.5.5 Regulatory Issues

The North Carolina Utilities Commission administers the use of expansion funds and natural gas bonds according to the same criteria. Both sources of funding are prescribed by their respective legislation to be used only for the “infeasible portion” of an expansion project. If at any time the proposed project becomes feasible, the Commission may require the expansion funds or bond funding to be returned. The economically infeasible portion of a project is defined as:

“In determining economic feasibility, the Commission shall employ the net present value method of analysis on a project specific basis. Only those projects with a negative net present value shall be determined to be economically infeasible for the company to construct.”⁸⁶

In calculating the net present value, the Commission uses a discount rate approximating the utility cost of capital. Additionally, in determining whether funds can be used, the Commission is required to consider:

- The scope of a proposed project, including the number of unserved counties and the number of anticipated customers that would be served; and,
- The total cost of the project.

3.5.6 Outcomes

Despite North Carolina’s relatively southern U.S. geography, which suggests that heating loads are not large, the expansion of its natural gas distribution system over the past 25 years has been a priority for policymakers. As of 2014, 96 out of 100 counties in North Carolina are being served by a gas LDC. The remaining 4 counties without an LDC franchise servicing them are all located in North Carolina’s mountainous west. Even there, one LDC is currently exploring ways to expand.⁸⁷

Since 1991, \$114.6 million USD of expansion funds have been used by three LDCs.⁸⁸ The table below provides a brief description of what these projects looked like.

⁸⁵ NCUC, 2012 and 2014.

⁸⁶ Quoted from *The Natural Gas Expansion/ Cost Act, 1991*.

⁸⁷ Frontier is “exploring ways to cost effectively expand into Allegheny County to serve the town of Sparta.” NCUC, 2014. Pg. 2.

⁸⁸ Note that a former LDC – the North Carolina Natural Gas Corporation (“NCNG”) – was acquired by Piedmont.

Figure 9: Projects Funded By the Use of Expansion Funds⁸⁹

Project	LDC	Expansion Funds/ Total Project Cost (USD)	Project Details	Customers Served
Alexander County Project	PSNC	\$4.3M/ \$6.2M	Completed February 2000. Included the installation of 24.9 miles of 6-inch steel transmission main.	23 residential 53 commercial 2 industrial
Bertie and Martin Counties Project	NCNG	\$10.3M/ \$12.6M	Completed December 1999. Included 39 miles of 12-inch transmission main.	122 residential 93 commercial
Columbus County Project	NCNG	\$3.4M/ \$5.6M	Completed June 2002. Included 21.2 miles of 6-inch transmission main.	54 residential 39 commercial 4 industrial
Haywood County Project	PSNC	\$4.1M/ \$7.2M	Completed January 1998. Included 7.6 miles of 6-inch transmission main.	303 residential 306 commercial 11 industrial
Mount Olive to Jacksonville Project	NCNG	\$16.6M/ \$24.0M	Completed September 1999. Included 58 miles of transmission pipeline.	997 residential 308 commercial 13 industrial (including military installations)
Madison, Jackson and Swain Counties Project	PSNC	\$28.4M/ \$31.4M	Three phases, completed in 2001, 2002 and 2004.	167 residential 210 commercial 10 industrial
McDowell County Project	PSNC	\$7.8M/ \$13.7M	Completed December 1998. Included 22.2 miles of transmission pipeline and 22.8 miles of distribution main.	205 residential 195 commercial 8 industrial
Mayland Project	Piedmont	\$38.5M/ \$41.4M	Completed September 2001.	558 residential 402 commercial 11 industrial
Franklin County Project	PSNC	\$1.1M/ \$3.7M	Completed December 2006. Included 4.4 miles of high-pressure distribution main.	1,299 residential 210 commercial 9 industrial

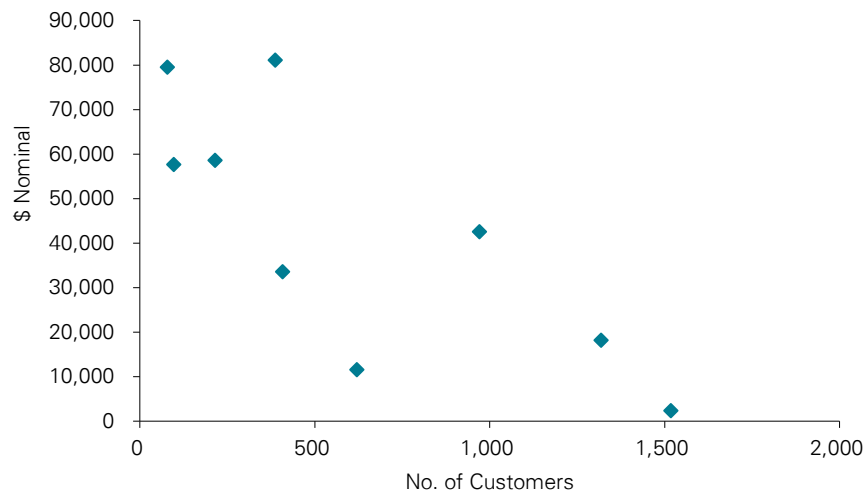
⁸⁹ Table compiled using data from 2012 NCUC biennial report.

The Exhibit below shows costs per customer served for each of the projects. Costs are divided into both those covered by the expansion fund and those covered by traditional funding. The data show that there was a wide range of costs per customer for the projects funded. Some of the differences will reflect the timing of implementation, since the data cover the period 1998 to 2006. Hence, costs will be influenced by inflation over the period. However, these differences should be small relative to the overall differences observed.

Total Cost Per Customer Connection (\$s)				
	Expansion Fund	Traditional Funding	Total	% Expansion
Alexander	55,100	24,400	79,500	69%
Bertie and Martin	47,900	10,700	58,600	82%
Columbus	35,100	22,700	57,700	61%
Haywood	6,600	5,000	11,600	57%
Mount Olive	12,600	5,600	18,200	69%
Madison	73,400	7,800	81,100	91%
McDowell	19,100	14,500	33,600	57%
Mayland	39,600	3,000	42,600	93%
Franklin	700	1,700	2,400	29%
Combined	20,400	5,600	26,000	78%

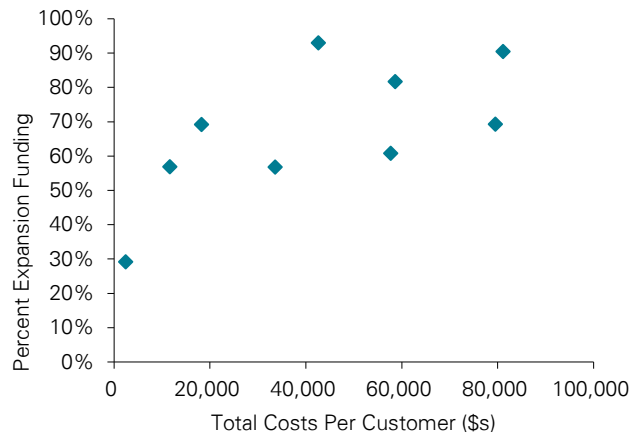
The graph below plots costs per customer against the number of customers for the projects. This graphic shows that projects with more customers tend to have lower costs per customer, although there is a wide dispersion in the points observed.

Costs per Customer versus No. of Customers



The graph below shows, for each project, the percentage of total costs covered by expansion funds, versus the total costs per customer. This graph shows that, as might be expected, higher per capita project costs have been associated with a higher proportion of expansion funding.

Percent Expansion Funding versus Total Costs Per Customer



By 2005, all \$200 million USD in natural gas bonds had been spent on 3 projects. However one of those projects – the Piedmont EasternNC Project – accounted for \$188.3 million USD in bond funds. At a total project cost of \$205.7 million USD, this also represented the largest expansion project in state history. It serves approximately 5,000 residential, 1,500 commercial and 10 institutional or industrial customers. (These figures imply a cost of about \$31,600 per customer.)

3.6 New Brunswick

3.6.1 Case Study Overview

This case study examines New Brunswick’s efforts to stimulate construction of a new province-wide natural gas distribution system, where none had previously been in place.

3.6.2 The Problem

In 1999, the development of the Sable Island natural gas fields off the coast of Nova Scotia made widespread natural gas distribution in New Brunswick a realistic possibility for the first time. The subsequent construction of a pipeline from Nova Scotia to Massachusetts – the Maritimes and Northeast Pipeline (“M&NP”) – would traverse New Brunswick, presenting the opportunity to build lateral transmission lines to communities deep into the province, including the Northeast and Northwest. The province began to revise its natural gas policy formally in 1998 and solicited bidders to distribute natural gas and amended its *Gas Distribution Act* in 1999. The MN&P pipeline became operational in 2000.

At that time, New Brunswick had no existing gas distribution facilities and half of the province’s approximately 756,600 people lived in rural areas.⁹⁰ Residential, commercial and industrial energy use was a mix of electricity, wood and refined petroleum. Diversifying energy supply was a policy priority of New Brunswick’s provincial government, as the local economy was and is dependent on a large, energy-intensive and resource-based manufacturing sector.⁹¹ Natural gas presented the

⁹⁰ Very limited local production and distribution in Moncton had ceased operations in 1991. *Source:* New Brunswick. Legislative Assembly. Select Committee on Energy. “Introduction.” *First Report of the Select Committee on Energy: Natural Gas for New Brunswick*. Legislative Assembly, November 1998. Web. March 2015.

⁹¹ New Brunswick. Natural Resources and Energy. Energy Policy Working Group. “White Paper.” *New Brunswick Energy Policy*. Natural Resources and Energy, 2000. Web. March 2015.

opportunity for a more efficient, cleaner-burning and competitively-priced fuel source. Policymakers emphasized the potential of natural gas to fuel electricity generation. Environmental benefits were important, too, since the burning of oil, diesel and coal in industrial activity and power generation had reduced air quality in the province.⁹²

The primary problem facing the province was not *whether* to expand gas distribution services into unserved areas but *how* to expand. Building a new province-wide natural gas distribution system, where none had previously been in place, would require a substantial upfront investment and considerable risk with respect to customer adoption. A government white paper on energy policy in 2000 highlighted:

“In New Brunswick, a challenge exists for development of natural gas infrastructure in that potential loads required to economically justify pipeline construction are concentrated in only a few locations. The population in the province is relatively low (756,600), with 52% living in rural areas. Approximately 1/3 of the population live in close proximity to the mainline and Saint John lateral.”⁹³

To address these challenges, government and regulatory decision-makers had to decide the length of time a new entrant should be permitted favourable treatment to compete for new customers, achieve profitability and transition to being regulated under a traditional cost-of-service regime.

Figure 10: Energy Use in New Brunswick – Percentage Breakdown By End-Use Sector, 1998

Energy Use in New Brunswick, 1998 ⁹⁴			
Fuel Source	Residential	Commercial	Industrial
Electricity	43	50	35
Wood	27	3	36
Refined Petroleum	30	47	29
Subtotal	100	100	100

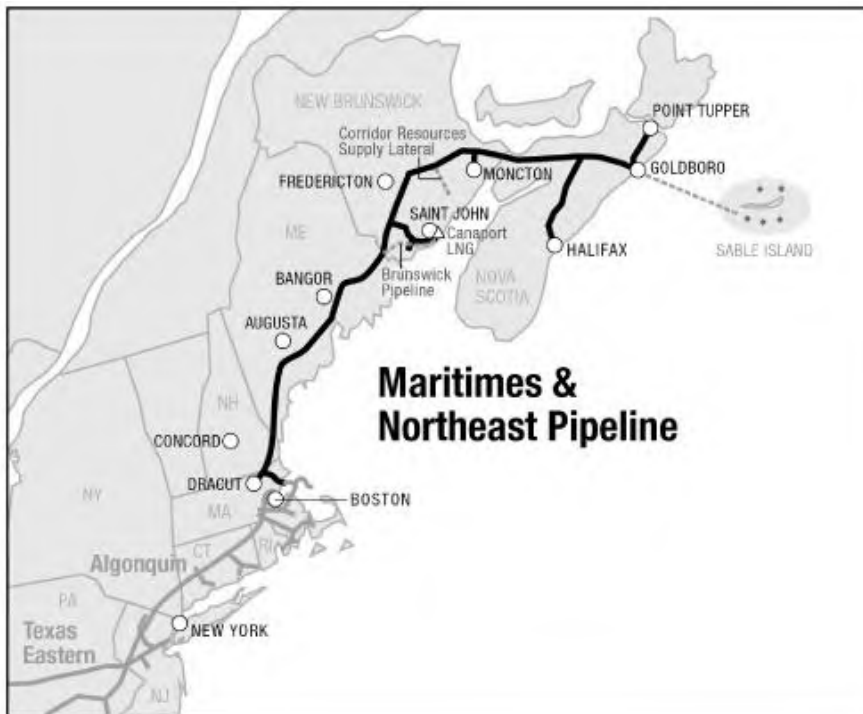
Source: Select Committee on Energy, Natural Gas for New Brunswick

⁹² Select Committee on Energy, 1998. “Environmental Benefits of Natural Gas.”

⁹³ Natural Resources and Energy, 2000. Pg. 34.

⁹⁴ Select Committee, 1998. “Energy Use in New Brunswick.”

Figure 11: Location of Sable Island and Maritimes & Northeast Pipeline



Source: U.S. Securities and Exchange Commission

3.6.3 Proposed Solutions

To develop, on a greenfield basis, a completely new natural gas distribution system with service across the province required a number of policy decisions and initiatives. The Legislative Assembly of New Brunswick appointed a Select Committee on Energy (“Select Committee”) that held a broad consultation, including a set of public hearings. In its final report, the Select Committee proposed, among other things, that:

- The provincial government should proceed to a formal Request For Proposals (“RFP”) process to solicit bidders for a new gas distribution franchise;
- Province-wide access to natural gas distribution services should be a key criterion in evaluating proposals;
- The government should evaluate bidders’ overall business plans and their ability to finance the business over the long term;
- The provincial government should avoid a broad policy of subsidies and incentives, with two exceptions:
 - The provincial government should “aggressively seek” financial support from the federal government to extend gas availability in the province; and,
 - The provincial government should provide a contribution in aid of construction to enable lateral construction into Northeastern and Northwestern New Brunswick if markets in those areas were inadequate to meet economic threshold tests; and
- All consumption of natural gas in the province should be regulated under a broad definition of gas distribution and be under provincial jurisdiction.

With respect to the necessity to regulate natural gas in the province, the Select Committee advised:

“The committee recommends the [Public Utilities Board⁹⁵ (“Board”)] be given flexibility in the methods it uses to determine a distribution company's charges to consumers. The Board should also have authority over such matters as revenue cycle services, supplier of last resort, load balancing, and the possible use of incentives in regulation.”⁹⁶

3.6.4 Tools Used

The Gas Distribution Act, 1999 separated gas distribution (i.e., the local distribution system) from gas sales (i.e., marketers). This separation was intended to promote competition in the retail market for the natural gas commodity and to limit “undue influence on the market” by a single distribution utility.⁹⁷ Policymakers had decided that a single general franchise agreement, rather than the use of multiple franchises, to serve all of New Brunswick would best accomplish the objective of uniform distribution rates and customer penetration by reducing “cherry picking” for distribution territories in densely-populated areas.⁹⁸ To promote lateral expansions from the MN&P, legislation allowed for the awarding of single end use franchises. These franchises were to be awarded by the Board and intended solely for a single industrial facility.⁹⁹ The province also retained the right to award local producer franchises for specific geographical areas involved in producing natural gas in New Brunswick.¹⁰⁰

In 1999, Enbridge Gas New Brunswick (“EGNB”) won the Province’s RFP to develop, design, construct, finance, operate, manage and maintain the proposed province-wide natural gas utility. EGNB was awarded a general franchise to service the entire province until 2020. Its initial projections were to serve 70,000 customers in 23 communities by the end of its franchise agreement.

On June 23, 2000, the Board issued its decision on EGNB’s application for approval of its rates and tariffs.¹⁰¹ The Board used a number of tools to provide EGNB with flexibility to expand into New Brunswick, and each of these topics are discussed in more detail in the next section:

- Streamlined regulatory processes;
- Regulatory flexibility during the initial development period, including with respect to its length of time;
- A market-based approach to rates;
- Rate riders during the development period;
- Postponement of cost of service studies; and,

⁹⁵ Also referred to at the time as the Board of Commissioners of Public Utilities and is now the New Brunswick Energy and Utilities Board.

⁹⁶ Select Committee, 1998. “Executive Summary.”

⁹⁷ Ibid.

⁹⁸ Natural Resources and Energy, 2000. Pg. 32-34.

⁹⁹ Single use franchises were subsequently only granted to large industrial companies in the Saint John area. *Source:* Enbridge Gas New Brunswick. “Independent Natural Gas Distribution Systems: In New Brunswick” *About Us*. (Corporate Website). EGNB, 2014. Web. March 2015.

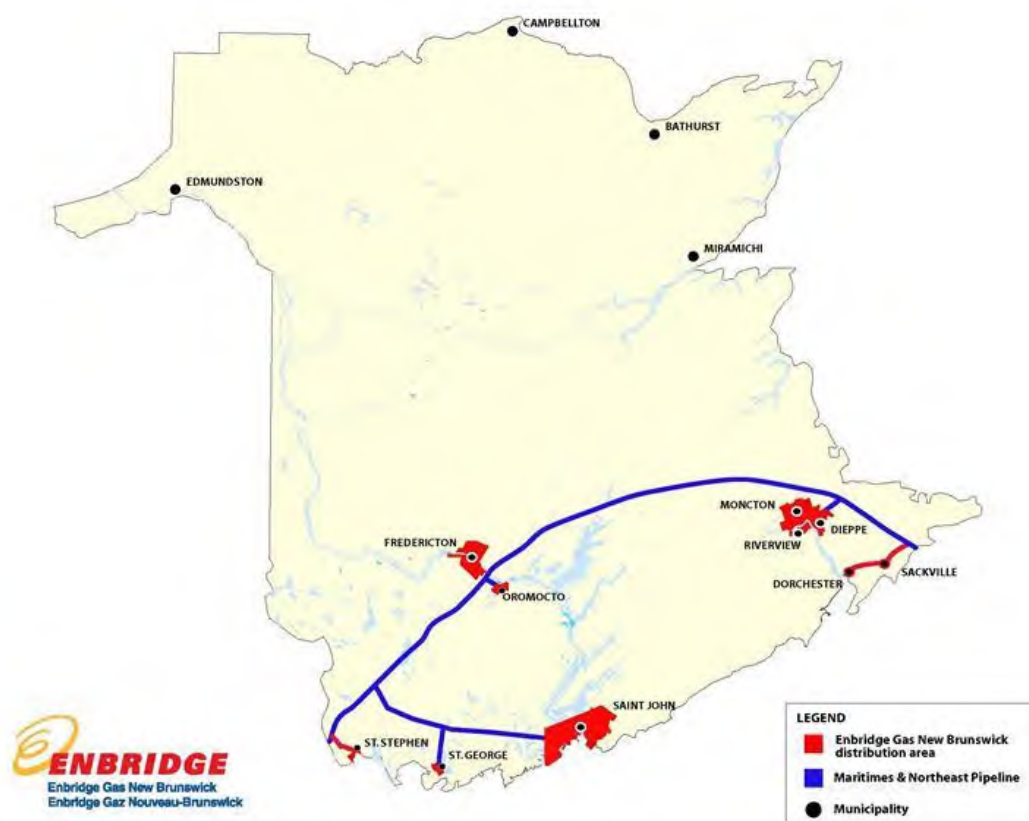
¹⁰⁰ Today, Potash Corporation of Saskatchewan Inc., located in Sussex, New Brunswick, is listed on the New Brunswick Energy and Utilities Board website as the sole Local Gas Producer Franchise Holder.

¹⁰¹ New Brunswick. Board of Commissioners of Public Utilities. “In the Matter of an Application by Enbridge Gas New Brunswick Inc. for Approval of its Rates and Tariffs.” *Decision*. Board of Commissioners of Public Utilities, 23 June 2000. Web. March 2015.

- Establishment of a deferral account amortized over the time between the development period and the end of EGNB’s general franchise agreement.

As part of the general franchise agreement awarded by New Brunswick, EGNB expected its capital structure would be organized with a 50:50 debt to equity ratio. For rate setting purposes, the agreement between the Province and EGNB originally provided for a deemed cost of debt that would be equal to the 10-year rate on a Government of Canada bond plus 2.5 percent. However, in its June 23, 2000 decision, the Board ruled that the cost of debt would be limited to the borrowing rate of EGNB’s parent company, Enbridge Inc., plus 1 percent.¹⁰² A return on equity of 13 percent was established for the development period.¹⁰³ Following EGNB’s rate hearing, and there being no objections from intervenors, the Board found that it would use EGNB’s actual debt to equity ratio rather than a target ratio – but with an equity amount not to exceed 50 percent.

Figure 12: Enbridge Gas New Brunswick Service Areas



Source: Enbridge Gas New Brunswick, 2013 Annual Report

3.6.5 Regulatory Issues

3.6.5.1 Streamlined Regulatory Process

EGNB filed its rates application on December 31, 1999 and the Board’s decision was issued on June 23, 2000. In several places in that decision, the Board acknowledged that “the use of traditional regulatory methods may not be appropriate in the early years of developing the industry.”¹⁰⁴

¹⁰² Ibid. Pg. 25.

¹⁰³ Any earnings above the permitted rate of return were to be applied directly to paying down the deferral account.

¹⁰⁴ Board of Commissioners of Public Utilities, 2000. Pg. 5.

Examples of traditional regulatory processes where the Board said it had been, or would be, flexible include:

- The Board asked parties to provide necessary information as quickly as possible to speed up decision-making;
- The Board established a committee process to resolve issues outside of the formal regulatory process to speed up decision-making and to reduce cost; and,
- The Board recognized that full public hearings on all rate changes could “add excessively” to the costs of regulation.¹⁰⁵

The Board also said that the regulatory framework described in its June 23, 2000 decision – which is outlined in the other sub-sections below – would provide “the proper balance between minimizing regulatory oversight and protecting the public interest.”¹⁰⁶

3.6.5.2 Development Period

Transitioning from a greenfield situation to a developed natural gas distribution system involved a number of risks. The price of natural gas fluctuated. There would be competition from existing players, such as fuel oil distributors, who would seek to retain their customers. Significant losses were expected in the initial years of development due to start-up costs. Therefore EGNB argued before the Board that to respond to these potential issues it required flexibility for an extended period of time. The period of time between the start of development and when the utility could be regulated on a cost-of-service basis as a mature utility was deemed to be the development period. To the Board, a mature utility implied one that could be expected to recover its full costs of service on an ongoing basis. EGNB estimated this would take 8 years.

In response, the Board agreed that a development period was appropriate but it did not agree to the initial 8-year request.¹⁰⁷ Instead the Board set a five-year deadline of December 31, 2005, after which the burden of proof would be on EGNB to justify an extension. The Board’s June 23, 2000 decision notes that there was “considerable discussion” about how the end of the development period should be determined. Samples of the criteria to be considered at a later time, in consultation with EGNB, were:

- Customer attachments;
- Rate of return on equity;
- Ability to forecast accurately;
- Volumes of gas flowing; and,
- Economic environment.

EGNB first applied to the Board in October 2004 to extend the development period from December 31, 2005, to December 31, 2010. In support of its application, EGNB cited lower levels of customer conversion and throughput than originally forecast, as well as higher per-unit costs. The Board granted this application and extended the development period to 2010.

In 2008, in advance of the expiry of the extended deadline in 2010, the Board scheduled a hearing to address the issue of the development period. The purpose of the hearing, which was a public proceeding, was to establish criteria for evaluating when the development period should end. In a December 1, 2009 decision, the Board found that while issues like the ones listed above are important considerations, they do not provide a basis by which to determine whether a *developing*

¹⁰⁵ Ibid.

¹⁰⁶ Ibid.

¹⁰⁷ Ibid. Pg. 8.

utility can be treated as a *mature* utility. Rather the Board devised a two-part test to distinguish between development and maturity:¹⁰⁸

- Can the utility's revenues recover its full costs on an annual basis?; and,
- Are those revenues sustainable?

The first part of the test requires a comparison of revenues to costs – if revenues are equal to or greater than costs, the first part of the test is satisfied. The second part of the test requires a determination of whether or not revenues will continue to be equal to or greater than costs going forward. In determining sustainability, the Board further explained:

“With respect to the appropriate period of time, the Board believes that use of a forecast period of two years is reasonable. The Board finds that the rates that could be charged on a sustainable basis are to be determined by using the approved rate setting method in force at the time of performing the test.”¹⁰⁹

In the Board's 2009 decision, it directed EGNB to file evidence by January 2010 on:

- The utility's cost of service;
- Proposed customer classes;
- Proposed rate design;
- Possible impacts of having different rate setting methods for different customer classes; and,
- A 10-year forecast identifying:
 - Number of customers for each class;
 - Throughput for each class;
 - Rates EGNB expects to charge;
 - Costs for each major expense category; and,
 - All other relevant information.¹¹⁰

Between the Board's 2009 decision and the present, the legislative and regulatory context in which EGNB operated changed, particularly with respect to how the deferral account (discussed in *Section 3.6.5.6: Establishment of a Deferral Account* below) is accounted for in setting rates. As a result, the Board ordered EGNB to file a new application by June 1, 2015 to determine the expiry of the development period.

3.6.5.3 Market-Based Approach to Rates

The market-based approach to rates proposed by EGNB, and subsequently approved by the Board, worked by setting targets for the all-in delivered price of gas vis-à-vis competing fuel sources (e.g., 30 percent below fuel oil costs in the residential market for those customers that had previously used fuel oil). The purpose of this approach, which would be applied on a “postage stamp” basis, was to incentivize customer conversion. Targets were set separately for each customer class, based on customers' avoided cost of either electricity or fuel oil and on assumed efficiencies for conversion of fuel or electricity to heat. While targets could be adjusted yearly to respond to market conditions, EGNB could not charge its customers any *more* than the targets established for a given year.

¹⁰⁸ New Brunswick. Energy and Utilities Board. “In the Matter of a Review of Issues Related to the Development Period for Enbridge Gas New Brunswick Limited Partnership.” *Decision*. EUB, 1 December 2009. Web. March 2015.

¹⁰⁹ *Ibid.* Pg. 5.

¹¹⁰ Energy and Utilities Board, 2009. Pg. 8.

A challenge with the market-based rate structure is that it meant that the rates that could be charged were very dependent on the commodity cost differential between natural gas and fuel oil. Natural gas prices increased dramatically in the early years of the development period. As a consequence, the all-in delivered cost of natural gas, particularly for residential consumers, was constrained by the 30 percent target savings required vis-à-vis fuel oil. This limited the amount that could be paid toward distribution services, since natural gas commodity costs still had to be recovered within the overall rate structure. The result of adverse commodity price movements was an increase in the distribution costs accumulating in deferral accounts.

In recent years, even with the decline in natural gas commodity costs, prices to residential consumers have continued to be constrained by the target price. Residential consumers therefore did not appear to benefit from lower gas commodity costs. Rather, the decline reduced amounts that were transferred to deferral accounts or that were borne by other customer classes. Distribution tariffs collected from residential consumers have continued to be below those that should be charged based on a full cost of service study, taking into account an appropriate allocation of costs among individual customer classes. Other customer classes have paid more than their share of the utility's costs, resulting in significant cross-subsidization among classes. This is observed through revenue to cost ratios that differ significantly from 1.0.¹¹¹ This has recently resulted in some large customers, notably Atlantic Wallboard Limited ("Atlantic Wallboard"), a subsidiary of J.D. Irving Ltd., seeking to exit the system. In response to a May 2014 increase to its distribution rates, Atlantic Wallboard, EGNB's largest customer, announced it would replace gas supplied by EGNB's system with compressed natural gas supplied by truck, which is not prohibited under New Brunswick's rules. The company claims it can save one million dollars a year with the change.¹¹²

Delays in market penetration may also have been the result of decisions on market structure. As noted above, the province implemented an open-access retail market as part of the new industry structure. The province envisaged that multiple retailers would compete for commodity supply and for related services, such as the sale of new gas appliances and furnaces. EGNB was therefore limited to the "default" supply of natural gas commodity and rules limited its ability to provide services that might be construed as providing unfair competition to retail energy suppliers. It can be argued that these constraints limited EGNB's ability to promote natural gas conversion.

3.6.5.4 Rate Riders During the Development Period

The Board approved the potential use of rate riders during the development period. This was meant to provide further flexibility to incentivize customer conversion. Rate riders were intended to be negative and used as necessary to provide further price reductions to one or more rate classes if required to respond to changing market conditions. Any shortfalls associated with the use of rate riders would be added to the deferral account. In 2014, in response to the changes in how the deferral account was accounted for in rate setting, EGNB requested and the Board approved the discontinuation of rate riders.

3.6.5.5 Postponed Cost of Service Studies

The Board granted EGNB's request to delay filing cost of service studies (revenue-to-cost ratios) until closer to the end of the development period. EGNB argued, and the Board agreed, that they would be of limited practical value at the beginning of greenfield development.

¹¹¹ Enbridge Gas New Brunswick. "Section 1.0 Application." *Review of 2013 Regulatory Financial Statements/ 2015 Rate Application*. Enbridge Gas New Brunswick, 27 June 2014. Web. March 2015. Pg. 4.

¹¹² K100 News. "Enbridge loses big customer." K100.ca. 26 May 2014. Web. March 2015.

3.6.5.6 Establishment of a Deferral Account

In recognition that EGNB's costs would be greater than revenues during the early years of the development period, the Board ruled that these costs could be deferred for recovery in the future. EGNB had originally proposed a 40-year amortization period and the use of two deferral accounts¹¹³:

- A Pricing Deferral Account ("PDA");
 - Including the deficiency caused by the Target Rates being established at a level that did not recover the full cost of service; and,
 - Including the deficiency resulting from the Actual Rates being lower than the Target Rates after Rate Riders had been used during the year; and,
- A Forecast Discrepancies Account ("FDDA").
 - Including the differences between actual and forecast revenues and cost of service that did not take into account any rate reduction that EGNB had to make to the Target Rates during the year which had to be captured in the PDA.

However the Board denied these requests. There was "no justification" for separating the deferral account "particularly for regulatory purposes". Instead the Board directed EGNB to establish one deferral account to record differences between Board-approved revenue requirements and the actual revenue EGNB received. The Board also expressed concern that, with respect to the amortization timeline, "such a long period of amortization will not necessarily be in the best interests of consumers."¹¹⁴ The Board ruled instead that the deferral account would be required to be cleared by the end of EGNB's general franchise agreement in 2020.

Through the deferral account, costs that could not be recovered from consumers in the early periods, given the need to keep rates at or below target levels, would be deferred until future years for recovery then. The deferral account recognized the reality that EGNB's total annual Revenue Requirement, based on cost of service principles, was greater than the actual revenues that could be raised from consumers in the early years. This reflects the fact that, while in the development period, the company had made large investments in new physical plant but still had a limited number of customers from whom to collect the associated costs. Amounts transferred to the deferral account were allowed to accrue interest at a rate equal to the utility's deemed cost of capital. This was to ensure that EGNB would be compensated for the delay in receipt of associated revenues.

As noted above, as a result of lower levels of customer conversion, less throughput and higher per-unit costs than originally forecast, EGNB applied to the Board in October 2004 to extend both the development period and the amortization period of the deferral account. EGNB argued extending the deferral account amortization timeline from the end of the franchise agreement in 2020 to the year 2040 was required because:

"It has become practically impossible for EGNB, without violating essential precepts of EGNB's rate/ business model, to recover the Deferral Account before the end of the term of the initial General Franchise Agreement."¹¹⁵

EGNB argued that in order to pay down the deferral account by 2020 it would require the utility to charge rates in excess of the market-based approach, thereby making the challenges facing the utility even worse. The Board ruled in favour of EGNB's request. In its decision, the Board noted the

¹¹³ Information summarized from the Board's June 23, 2000 decision. Pg. 29.

¹¹⁴ Ibid. Pg. 31-32.

¹¹⁵ Enbridge Gas New Brunswick. *Application to Extend the Development Period and the Deferral Account Recovery Period*. EGNB, 8 October 2004. Web. March 2015.

discrepancy between what EGNB had originally forecasted as the peak amount of the deferral account (\$13 million) and the forecasted peak at that time, which was \$132.9 million.¹¹⁶

3.6.6 Outcomes

Today EGNB has approximately 12,000 customers in 10 New Brunswick communities, but its distribution system was built to serve a total of 30,000 homes and businesses.¹¹⁷ The company's investment totalled more than \$400 million and included construction of approximately 800 kilometres of distribution pipeline.¹¹⁸ However EGNB's original proposal estimated that the utility could reach 70,000 consumers in 23 communities by the end of its franchise agreement in 2020. Hence, distribution build-out and market penetration have been much lower than were originally forecast.

Fuel-switching was slow to start in New Brunswick, and the specific causal factors have been debated in the years since. Contributing factors that have been cited include:

- The prevalence of many sparsely-populated communities, which increased the time and cost required to build out the distribution system and meant that fewer customers were passed by the system;
- The presence of existing home heating systems, such as electric baseboard, which increased customers' costs for conversion;
- Customer adoption projections that did not materialize;
- The structure of franchise agreements;
- Market-based rate structures;
- EGNB's build-out plans; and,
- Lack of effective regulatory and legislative oversight.¹¹⁹

From the perspective of the utility, a consequential decision was made early in New Brunswick's attempts to provide natural gas distribution. The Select Committee proposed, and changes to *The Natural Gas Act* included, the segregation of franchise agreements into three types:

- **General Franchise Agreement** – a franchise to distribute gas throughout New Brunswick;
- **Single End Use Franchise** – a franchise granted to a specific industrial facility; and,
- **Local Gas Producer Franchise** – a franchise granted to a local gas producer.

In its 2011 submission to the New Brunswick Energy Commission, EGNB argued:

“The New Brunswick natural gas distribution system operates under highly unusual conditions with the existence of single end use franchises that allow several large industrial users, representing more than 80 percent of the natural gas consumed in the province, to entirely bypass the system. Virtually all natural gas distribution systems in North America have been developed without single end use franchises. Consequently, these large users have never contributed to the development of the

¹¹⁶ New Brunswick. Board of Commissioners of Public Utilities. “In the Matter of an Application dated October 8, 2004 to Request Extension of the Development Period and the Deferral Account Recovery Period.” *Decision*. Board of Commissioners of Public Utilities, 21 January 2005. Web. March 2015.

¹¹⁷ Enbridge Inc. *Annual Report*. Enbridge, 2013. Web. March 2015; and Enbridge Gas New Brunswick. “Natural Gas: A Strategic Piece of the Energy Puzzle.” *Submission to the New Brunswick Energy Commission*. EGNB, 2011. Web. March 2015.

¹¹⁸ *Ibid.*

¹¹⁹ Atlantica Centre for Energy. “A Clean Break: Resetting the Natural Gas.” *Distribution System in New Brunswick: Economic Development & the Public Interest*. Atlantica Centre for Energy, 3 June 2011. Web. March 2015.

distribution system which has had a profound effect on how the system has developed to date.”¹²⁰

The original rationale for this market structure, as explained in a year 2000 New Brunswick Department of Natural Resources and Energy white paper:

“The objective is to encourage large industrial customers to act as anchor loads in securing laterals and serves to satisfy the Province’s desire to use the Maritimes and Northeast Pipeline lateral policy for as long as it is in effect. The single end use franchise fee was set at \$50,000 annually, indexed to the consumer price index. This amount was determined as sufficiently large to ensure that small and medium-sized consumers would find value in being served by the distribution company while not being so high as to negatively impact the likelihood that large customers would become anchor loads to the laterals. In support of developing a safe and effective natural gas industry in New Brunswick, the Province will direct all franchise fees to help defray expenses of the Board, particularly for costs associated with pipeline safety.”¹²¹

From the government’s perspective, the issue of high distribution rates and low customer adoption was attributable to the continued use of market-based rate targets instead of the cost-of-service structure of mature markets. The unintended consequence, according to the Province’s 2011 Energy Blueprint was that “the benefits of current and projected future low gas commodity prices are not being passed onto the consumer.”¹²²

As a response, the Government of New Brunswick tabled legislation in 2011 to change the way EGNB’s rates were regulated, which in turn had the effect of disqualifying EGNB from using rate-regulated accounting.¹²³ EGNB was no longer allowed to build recovery of certain deferred costs into its rates going forward. This change resulted in EGNB writing off \$262 million worth of assets. The company initiated legal proceedings against the Province for damages in breach of its contract. These proceedings continue to the present time.

3.6.7 Observations

Experiences with Enbridge Gas New Brunswick show the challenges of building a completely new distribution system on a greenfield basis. For example:

- EGNB’s initial financial projections were built on the assumption that revenue shortfalls in the early years, relative to the utility’s Revenue Requirement under traditional cost of service methods, could be deferred for recovery in later years. When circumstances changed such that shortfalls grew relative to forecast, this resulted in a rapid growth in deferral accounts to the point where they could no longer be easily recovered.
- Capital expansion costs proved to be higher than initially forecast. This was partly because of challenges associated with the local topography. Capital cost increases put additional pressure on the relative competitive position of natural gas service versus alternative, incumbent fuels and had a negative effect on the utility’s financial position.
- The market-based rate structure resulted in large losses in the early franchise years and, in later years, the perception that savings from low gas commodity prices were not being passed onto consumers, which created a negative public perception toward natural gas fuel-switching.

¹²⁰ EGNB, 2011. Pg. 6.

¹²¹ Natural Resources and Energy, 2000. Pg. 30.

¹²² New Brunswick. Department of Energy. *The New Brunswick Energy Blueprint*. Department of Energy, October 2011. Web. March 2015. Pg. 26.

¹²³ Enbridge Inc., 2013. Pg. 77.

- Multiple franchises allowed industrial customers to by-pass EGNB's system. These customers could have been used as anchor loads, able to contribute to the development of the distribution system. An anchor load could have stabilized the financial performance of the utility service provider and potentially reduced the quantum of costs subject to deferral.

4 Observations

Based on our review of experiences with natural gas distribution system expansion in six other North American jurisdictions – Alaska, Connecticut, Maine, New York, North Carolina and New Brunswick – we provide a number of observations as outlined below. These observations may assist the Board in its consideration, as per its letter of February 18, 2015, regarding regulatory flexibility pertaining to proposed system expansion projects.

4.1 Summary Findings

- Although the extension of natural gas service to rural, remote or sparsely-populated unserved or underserved areas was a policy priority in all six case studies, no jurisdiction we evaluated was prepared to deviate significantly from the practice of using an economic test – based on a net present value calculation or similar metric – for determining whether a proposed expansion project should be approved. Policymakers and regulators were therefore challenged by the need to mitigate the upfront capital cost of expanding service, to encourage customer conversions and to maintain a rate structure that reflected well-established cost allocation and rate-design principles.
- We did not observe an explicit preference in the jurisdictions examined for inviting new entrants, creating new service territories or using municipally-based systems to address a lack of service in rural areas. In Alaska and Maine, new entrants competed alongside incumbents and were awarded franchise areas based on the merit of their respective proposals. In Connecticut, New York and North Carolina, the tools and approaches used to encourage the extension of natural gas service either favoured or were directed at incumbents. This may reflect the economies of scale typically associated with network monopolies such as natural gas distribution, even when service is being expanded into unserved areas.
- While broader public policy goals were important to local decision-makers in all of the jurisdictions we examined, decision-makers were generally not willing to broadly socialize the costs associated with extending service to areas that did not pass the economic test over the existing natural gas distribution grid and existing natural gas distribution customers. The tools and approaches used in each of the case studies we examined implicitly recognized that customers have access to alternative fuels. As such, the overall system cost, on a bundled basis, needed to remain competitive with alternative energies.
- There was an emphasis across jurisdictions on identifying and prioritizing industrial, commercial or institutional anchor loads. These large-scale users of natural gas, with consistent and predictable consumption, served as the basis for further retail-oriented expansion in a given area. Anchor customers often are in a position to make long-term commitments to natural gas service, see significant savings from conversion early and can help to defray a large portion of the expansion costs.
- With the exception of North Carolina, where certain refunds/ monies were made available to natural gas distributors from the upstream transportation sector, none of the jurisdictions we examined were willing to impose a surcharge or subsidy on the commodity cost of natural gas to fund system expansions. This is consistent with the evolution of rate regulation such that commodity costs are generally a straight pass through to customers without mark-up, and distribution system costs are determined on a stand-alone basis.
- Regulatory commissions have approved expansion programs in response to executive or legislative mandates, requests from existing franchised utilities or from potential new entrants or on their own initiative. To facilitate expansion efforts, regulators experimented with time-limited, project-specific innovations that demonstrated flexibility with respect to (i) relaxed criteria for approving expansion; (ii) inclusion of future construction financing through temporary surcharges; (iii) extended development periods to achieve profitability; and, (iv) new entrants willing to accept reduced rates of return on equity.

- A move to more transparent reporting was a feature of the policy frameworks in Connecticut, New York and North Carolina. The policymakers or regulators asked for periodic reporting on the number of requests received from potential customers in unserved or underserved areas (e.g., anchor loads, rural communities). This allowed policy makers to review progress toward intended goals and aided in modifying new approaches during the early stages of expansion programs.
- Examples of government assistance and the levels of public funding, if applicable, varied from jurisdiction to jurisdiction and over time. Some jurisdictions were willing to use the government's ability to borrow at lower rates in order to help finance expansion projects, thereby reducing utilities' weighted average cost of capital. In turn, a requirement for lower returns improves outcomes under existing economic tests associated with new service expansions. Other examples of government support included direct on-lending of funds raised through public sources and indirect grants funded outside of target development areas.
- Extending gas distribution systems into unserved or underserved areas has a risk profile that is greater than the risk of the existing system, on average. Extensions potentially span multiple years and rate-setting cycles. Project risks include (i) lower than forecast customer conversions; (ii) under-recovery of the revenue requirement associated with the cost of service, including the return on and of capital, and the potential stranding of assets and of regulatory deferral accounts; (iii) capital cost overruns; (iv) policy risk; and, (v) regulatory risk.
- With the exception of the major greenfield development in New Brunswick, we did not observe an extensive use of deferral and variance accounts to postpone the recovery of costs associated with natural gas system expansions. As noted in our section on New Brunswick, reliance on deferral accounts can create significant financial challenges when actual results vary from forecast.

Overview of Jurisdictional Review of Natural Gas Distribution System Expansions

Jurisdiction	Starting conditions	Enabling legislation or policy support	New entrant integral to system expansion efforts	Regulatory flexibility around traditional economic tests	Other notable features
United States					
Alaska	<ul style="list-style-type: none"> • Very few customers outside of downtown Fairbanks with access to natural gas. 	<ul style="list-style-type: none"> • Interior Energy Plan 	<ul style="list-style-type: none"> • Yes, the creation of a new municipally-owned LDC – Interior Alaska Natural Gas Utility. 	<ul style="list-style-type: none"> • Regulator’s decision based upon competing proposals to supply same area. 	<ul style="list-style-type: none"> • LNG used to supply remote, underserved area.
Connecticut	<ul style="list-style-type: none"> • 216,000 customers on-main but not converted. • 89,000 off-main but considered feasible. 	<ul style="list-style-type: none"> • Comprehensive Energy Strategy 	<ul style="list-style-type: none"> • No, program relied on incumbent utilities. 	<ul style="list-style-type: none"> • Proposed extension of payback period used in hurdle rate tests; alternative rate riders; flexibility in calculating extension costs. 	<ul style="list-style-type: none"> • Proposal to require LDCs to submit annual expansion plans tracking multiple factors.
Maine	<ul style="list-style-type: none"> • Only one out of twenty households use natural gas for space heating. 	<ul style="list-style-type: none"> • Long-standing policy favouring competition. • Non-exclusive gas franchise territories. • In 2012, legislation authorized state bond financing for expansion projects. 	<ul style="list-style-type: none"> • Yes, approval of Summit Natural Gas of Maine to service 17 communities in central Kennebec Valley. 	<ul style="list-style-type: none"> • Approval of utility-specific 10-year rate proposal, including CIAC charges rolled into rates and reduced ROE. 	<ul style="list-style-type: none"> • “Second utility” status allows new entrants to serve alongside incumbents.
New York	<ul style="list-style-type: none"> • One million households without gas located within existing service territories. 	<ul style="list-style-type: none"> • New York Energy Highway Blueprint • PSC Technical Conference to review natural gas policies. 	<ul style="list-style-type: none"> • No, program relied on incumbent utilities. 	<ul style="list-style-type: none"> • Use of 10-year development period (instead of five years) enabled proposal to satisfy economic test. 	<ul style="list-style-type: none"> • Several utilities in New York State. Public Service Commission regulates 19 LDCs.
North Carolina	<ul style="list-style-type: none"> • In 1989, 38 counties out of 100 with no or minimal gas service. • 20 of the 38 counties in unfranchised territories. 	<ul style="list-style-type: none"> • Natural Gas Planning Act, 1989 • Natural Gas Expansion/ Cost Act, 1991 • Clean Water and Natural Gas Critical Needs Bond Act, 1998 	<ul style="list-style-type: none"> • No, program relied on incumbent utilities. 	<ul style="list-style-type: none"> • Expansion funds and natural gas bonds used only for economically infeasible (i.e., negative net present value) portions of expansion projects. 	<ul style="list-style-type: none"> • \$510 million USD invested to expand gas distribution system: \$200M from natural gas bonds; \$115M from LDC expansion funds; \$195M primarily from LDC investors.

Overview of Jurisdictional Review of Natural Gas Distribution System Expansions

Jurisdiction	Starting conditions	Enabling legislation or policy support	New entrant integral to system expansion efforts	Regulatory flexibility around traditional economic tests	Other notable features
Canada					
New Brunswick	<ul style="list-style-type: none"> Greenfield situation. No existing natural gas distribution system. Construction of the MN&P pipeline. 	<ul style="list-style-type: none"> Select Committee recommendations Government RFP to award franchise Gas Distribution Act, 1999 	<ul style="list-style-type: none"> Yes, Enbridge Gas New Brunswick received General Franchise, subject to Single End Use and Local Gas Producer Franchises. 	<ul style="list-style-type: none"> Extended development period; market-based rate; deferral account for unrecovered revenue requirement. 	<ul style="list-style-type: none"> Subsequent legislative changes made to original franchise agreement resulting in protracted legal dispute.

Overview of Expansion Results

Jurisdiction	Utility	Customers added to date	Original projections	Type/ amount of government assistance	Total Project Cost
Alaska	<ul style="list-style-type: none"> Interior Gas Utility 	<ul style="list-style-type: none"> 0 Expected Q3 of 2016 	<ul style="list-style-type: none"> 1,403 by 2018 13,336 by 2022 	<ul style="list-style-type: none"> \$150 million in loans for expanding local distribution system 	<ul style="list-style-type: none"> \$360 million for total Interior Energy Plan
Connecticut	<ul style="list-style-type: none"> Various 	<ul style="list-style-type: none"> Not available 	<ul style="list-style-type: none"> ~300,000 by 2020 	<ul style="list-style-type: none"> Proposals aimed at accelerating customer conversions with on-bill financing 	<ul style="list-style-type: none"> ~\$1.44 billion to serve all off-main customers
Maine	<ul style="list-style-type: none"> Summit Natural Gas of Maine 	<ul style="list-style-type: none"> 1,500 in Kennebec Valley 1,500 in CFY¹ 	<ul style="list-style-type: none"> 52,000 potential in Kennebec Valley 8,000 by 2018 in CFY¹ 	<ul style="list-style-type: none"> Not applicable 	<ul style="list-style-type: none"> \$350 million for Kennebec Valley Project \$72.5 million for CFY¹ Project
New York	<ul style="list-style-type: none"> New York State Electric & Gas 	<ul style="list-style-type: none"> Not available 	<ul style="list-style-type: none"> 1,200 (potential) by 2017 	<ul style="list-style-type: none"> Not applicable 	<ul style="list-style-type: none"> \$9 million
North Carolina	<ul style="list-style-type: none"> Various 	<ul style="list-style-type: none"> 5,612 customers² 6,719 customers³ 	<ul style="list-style-type: none"> Not available 	<ul style="list-style-type: none"> \$200 million in natural gas bonds 	<ul style="list-style-type: none"> \$510 million total: \$200M from natural gas bonds; \$115M from LDC expansion funds; \$195M primarily from LDC investors
New Brunswick	<ul style="list-style-type: none"> Enbridge Gas New Brunswick 	<ul style="list-style-type: none"> 12,000 customers 10 communities 	<ul style="list-style-type: none"> 70,000 by 2020 23 communities 	<ul style="list-style-type: none"> Not applicable 	<ul style="list-style-type: none"> EGNB investment to date of \$400+ million

¹ Cumberland, Falmouth and Yarmouth, Maine

² Includes residential, commercial and industrial customers from LDC expansion funds (as of December 2011)

³ Includes residential, commercial and industrial customers from natural gas bonds (as of December 2011)

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Appendix 1 Other Jurisdictions

This section provides an overview of policies in other jurisdictions with respect to the expansion of natural gas distribution systems. Some of these policies are already in place, while others are under consideration.

Canada

Alberta

There are more than 50 rural gas co-ops in Alberta. These co-ops formed throughout the 1960s and 1970s in response to the lack of distribution services in rural areas.¹²⁴ In 1973, the provincial government created the Rural Gas Program, which allowed rural gas co-ops to form exclusive franchise areas. The program also included government assistance in the form of grants for extending gas lines to rural farms and households. This assistance, which continues today as the Rural Gas Grant Program, is intended to partially offset the costs of construction for extending new service. Eligible rural utilities – co-ops, municipal or First Nations – can apply for funding under a formula. As of 2013, 75 percent of costs above the threshold of \$6,000 per residence or farm is eligible for support. Where costs exceed \$20,000, anything above that threshold is ineligible for the grant. Today, the Federation of Alberta Gas Co-ops Ltd. is responsible for administering the Rural Gas Grant Program, while the provincial government remains the source of funding.

Saskatchewan

From 1982 to 1991, Saskatchewan extended natural gas distribution services to rural communities under the Rural Gas Distribution Program, which provided government assistance for the installation of gas lines. The Saskatchewan Association of Rural Municipalities is currently lobbying the provincial government to reintroduce the program.¹²⁵ Today, SaskEnergy – the province's gas LDC, a provincial Crown corporation – reaches 93 percent of Saskatchewan residential, farm, commercial and industrial customers. Service reaches all but the most northern and remote communities.¹²⁶ While SaskEnergy management has explored future expansion to some of these communities using LNG, these plans are still in the preliminary stages.¹²⁷

United States

Delaware

Delaware's 2009-14 Energy Plan included the policy goal of facilitating the expansion of natural gas transmission and distribution. However, given Delaware's small geographic size, state policies are primarily aimed at infilling underserved areas, as opposed to reaching remote, rural or sparsely-populated unserved areas.

Indiana

In Indiana, utility extension projects into rural areas are eligible for rate adjustments, or trackers, called Transmission, Distribution and Storage System Improvement Charges ("TDSIC"). The Indiana Utility Regulatory Commission reviews 7-year infrastructure improvement plans filed by utilities

¹²⁴ Background information in this section is primarily derived from the Federation of Alberta Gas Co-ops Ltd. *Source:* Federation of Alberta Gas Co-ops Ltd. "Federation History." *Who We Are*. Federation of Alberta Gas Co-ops Ltd., 2015. Web. March 2015; and Federation of Alberta Gas Co-ops Ltd. "Rural Gas Grant Program." *Public Info*. Federation of Alberta Gas Co-ops Ltd., 2015. Web. March 2015.

¹²⁵ Saskatchewan Association of Rural Municipalities. "Resolutions: Rural Gas Program." *Advocacy*. SARM, 2014. Web. March 2015.

¹²⁶ SaskEnergy. *About SaskEnergy*. Web. March 2015.

¹²⁷ Saskatchewan. Legislative Assembly. Standing Committee on Crown and Central Agencies. "Hansard Verbatim Report." *No. 40*. Twenty-Seventh Legislature. Legislative Assembly, 1 December 2014. Web. March 2015.

seeking to use this rate mechanism. If approved, TDSICs may be used to finance rural expansion projects subject to a variety of conditions, such as (i) rate increases limited to once every 6 months; (ii) rate increases limited to no more than 2 percent of total annual retail revenues; and (iii) utilities can recover 80 percent of costs as incurred, with the remainder deferred until the next base rate case.

Michigan

Michigan has well-developed production, transmission and distribution infrastructure that reaches most of the state population, including the Upper Peninsula, through 10 LDCs. While new legislation was before the Michigan legislature in 2014 to encourage additional residential propane-to-gas conversions – and estimates are as high as 200,000 potential new gas customers – state initiatives are primarily related to in-filling underserved areas as opposed to reaching remote, rural or sparsely-populated unserved areas.

Minnesota

Instead of requiring upfront payment for the uneconomic portions of expansion projects, Minnesota allows utilities to apply “New Area Surcharges” to all customer bills within the expansion area. These surcharges last for a flexible, project-specific period of time (e.g., until all uneconomic costs are recovered) and/ or for a fixed period of time (e.g., as long as 20 years in some cases).

Mississippi

Mississippi is a significant regional hub for natural gas infrastructure and is seeking to leverage its gas distribution system to encourage economic growth. One LDC (Atmos Energy Corp.) has been granted approval to charge all of its existing customers a “Supplemental Growth Rider” to finance the uneconomic portions of extensions to industrial anchor loads.

Nebraska

Nebraska passed legislation in 2012 allowing utilities to apply a “Rural Infrastructure Surcharge” to customers within an expansion area and, if necessary, apply the surcharge to a broader set of utility customers.

New Jersey

The 2011 New Jersey Energy Master Plan included the policy goal of expanding natural gas distribution services to unserved areas – primarily in Southern New Jersey. However, interstate transmission pipelines and the role of natural gas in electricity generation are bigger priorities for state policymakers. New Jersey already has one of the highest concentrations of natural gas use in the U.S., according to the plan, with 70 percent of residents using natural gas for home heating.

Ohio

In 2014, Ohio lawmakers passed a bill permitting natural gas companies to apply infrastructure development riders to recover costs of extending gas distribution services to economic development projects. Eligible economic development projects included commercial, industrial and manufacturing facilities, as well as projects in areas where adequate natural gas infrastructure was not available. These riders can be applied to all customers of the natural gas utility, as approved by the Public Utilities Commission of Ohio.

Appendix 2 New York Public Service Commission Discussion Questions

In advance of its January 9, 2013, technical conference on natural gas expansion, the New York State Public Service Commission issued the following list of questions to participants for further discussion. These questions originally appeared as an appendix to the order instituting the proceeding, dated November 30, 2012, and are presented here in the same way.

ISSUES TO BE CONSIDERED AT THE TECHNICAL CONFERENCE

Barriers to Extension and Expansion of Natural Gas Facilities

1. Please explain your understanding (and for utilities, your implementation) of Commission regulations and the Natural Gas Expansion Policy including your views on whether they encourage or deter expansion of the natural gas delivery system in New York State. Do you feel that the Commission regulations and Policy should be modified and if so, how?
2. Regarding the Commission's regulations of the natural gas delivery system and the system itself, do you believe that the interests of utility shareholders, ratepayers, and the State as a whole are aligned? Please explain.
3. Are there provisions of current policies or regulations that appropriately incentivize the expansion of the natural gas delivery system in New York State? Are these sufficient? If not, please suggest alternatives.
4. Identify current barriers inhibiting conversion to natural gas usage from other heating fuels – other than the cost of replacing heating equipment. Please explain how the barrier inhibits conversion and provide suggestions for reducing or eliminating the barrier – including the cost of replacing heating equipment.
5. Please identify the outreach and education efforts currently employed by the utility for the purposes of gauging interest in natural gas service and/ or soliciting new customers in areas where interest in the possibility of obtaining service has been expressed. Are the efforts sufficient? How can they be improved? Would expanded or improved outreach and education programs increase conversion to natural gas by customers who reside within the 100 feet zone of existing utility infrastructure (and, accordingly would not pay for the extension)? How can the utility identify, communicate and engage with such customers? When an individual customer requests service, please describe the utility's efforts to communicate with or solicit other customers in the neighborhood/ area.
6. Please identify the typical flow of communication and information between the utility and a customer requesting service that would require extension of a gas main sufficient to require a surcharge. Please provide any examples of written communication.
7. What issues should be given consideration prior to expansion of the natural gas delivery system? Should such considerations include protections for a group or groups of customers? If so, what should be and what types of protections should be considered?
8. Are there existing utility specific pilot programs focused on new approaches to line extensions or new franchise expansions of the natural gas delivery system? If so, please describe the pilot program. If not, could such a pilot program be beneficial and, how would it be designed?

Rate and Ratepayer Considerations

9. The Commission's regulations (§230.2(f)) provide that "each corporation may, in its tariff schedules, extend such obligation [to provide certain main and service line extensions without cost to the customer], to the extent the provision of additional facilities without charge is cost-justified." Identify whether the utility ever provides residential customers with more than 100 feet of gas main or service line without surcharge. Please explain why and under what circumstances or, if never, why not. Is the utility aware of any geographic areas in its service territory where potential cost justified extensions of greater than 100 feet are currently un-served? If not, has the utility ever attempted to ascertain or develop such information? What should be the appropriate length of main and/or service provided without surcharge? Please explain.

10. Does the utility provide programs that could assist low income customers or those on a fixed income to overcome the barriers to conversion to natural gas?

11. Are there potential funding mechanisms for expansion of the natural gas delivery system other than through utility rates or direct customer payments (surcharges, CIACs or other)?

12. Are existing natural gas efficiency programs adequate and optimal to serve the expansion of customers within 100 feet of existing utility infrastructure? If not, what changes, including possibly the level of funding, could be made to improve the existing efficiency programs? Would efficiency programs targeted to conversion customers result in increased energy savings, and if so, how?

13. Do Revenue Decoupling Mechanisms (RDMs) impact expansion of the natural gas delivery system?

Economic Development

14. Does the utility have any information or estimates concerning the existence of commercial or industrial customers who may add and/ or retain jobs if they could switch their process or heating fuel to natural gas? If so, how many jobs might be added or retained?

15. Are there specific industries in the State that would benefit from an expanded natural gas delivery system? Please describe.

Public/ Private Partnerships

16. Are there potential partnerships between various entities involved in the energy and heating markets in New York State that could facilitate expansion of the natural gas delivery system? If so, please provide examples and whether your organization would be willing to take part in such a partnership. Who would be best suited for encouraging and developing such partnerships? What role should the public sector play?

17. Are there programs currently administered by utilities or federal, state or local agencies that assist customers with heating fuel conversions? Are there roles that other agencies, such as the New York State Energy Research and Development Authority (NYSERDA), should play in expansion of the natural gas delivery system? Should the Energy Efficiency Portfolio Standard (EEPS) programs be expanded or modified to encourage conversions to natural gas before end-of-life replacements?

18. Are there opportunities to coordinate natural gas delivery system expansion projects with other available resources, such as economic development, energy efficiency, or environmental protection? Please provide specific examples, if possible.

Environmental Impact

19. Are there changes that could be made to the environmental impact review process involved in granting or expanding gas franchise areas that could improve or streamline the process?

20. Please identify, if any, areas of the State where provision of natural gas delivery service is unrealistic because of environmental constraints, construction permitting requirements or other factors and explain why service to such areas is believed to be unrealistic. Are there any areas of the State that require special consideration regarding expansion of the natural gas system?

Planning

21. Please explain your utility's natural gas delivery system expansion planning process including any large-scale and or long-term plans that are in place or are being considered.

Appendix 3 National Regulatory Research Institute Discussion Questions

Ken Costello's 2013 policy paper for the National Regulatory Research Institute entitled "Line Extensions for Natural Gas: Regulatory Considerations" was one of the most widely-cited sources during the course of our research. The paper concludes with a list of questions state utility commissions can ask about gas-line extensions. That list is presented here for further consideration.

QUESTIONS STATE UTILITY COMMISSIONS CAN ASK ABOUT GAS-LINE EXTENSIONS

1. What are the benefits and costs of line extensions from the perspectives of (a) the utility, (b) existing customers, (c) new customers, and (d) society at large (e.g., local economy, accounting for environmental benefits)? If they differ, what implication does this have for policy?
2. When should a utility extend its lines? What are the necessary conditions? What is efficient and economical service expansion?
 - When prospective customers indicate their commitments to immediate demand?
 - Before or ahead of known (i.e., firm, committed) demand but in potentially high-growth areas?
 - If the latter, how should the utility recover any current or future revenue deficiencies?
3. What is the proper balance of risk and reward for the utility and its customers?
4. Should regulators distinguish between main lines in underdeveloped and undeveloped (e.g., rural locations without previous gas service) areas? If so, what are the implications for policy?
5. Who should pay for lines?
 - How much should new customers pay?
 - Existing customers?
 - Utility shareholders, government taxpayers?
 - What is a fair sharing of the costs?
6. How can a commission ensure a utility that it will recover all of its prudent costs for investments in line extensions?
7. Can subsidization of new customers ever be justified?
 - What do we mean by subsidization in this context?
 - Is this situation similar to the federal government subsidizing rural electric co-ops to expand electric service to areas that otherwise would not be served because of the unprofitability to investor-owned utilities?
8. How should the utility recover their costs from new customers?
 - Through an existing ratemaking mechanism?
 - Through some other mechanism (e.g., special surcharge)?
9. Should the utility recover any incremental costs from existing customers?
 - Should existing customers be always held harmless when a utility extends service to new customers?
 - If not, under what conditions?

10. Over what period should a utility recover the costs for line extensions that pass an economic test?

11. Should utilities offer “no cost” extension lines to new customers? If so, who should pay for them?

12. How should utilities structure customer contributions?

- What is their rationale?
- How large should they be?
- Over what timeframe should utilities recover them (e.g., one-time up-front, amortized over five years)?
- Should they include refunds? If so, what are the criteria for refunds?
- How can utilities design up-front customer contributions so as not to discourage fuel switching to gas that is economical?
- Could customer contributions place utilities at a competitive disadvantage with other fuels?
- Under what conditions, if any, should regulators include facilities paid for by customer contributions in rate base?

13. Should regulators approve line-extension projects that may not be economically feasible using traditional criteria, like NPV and IRR?

14. What incentives and disincentives does a utility have to invest in new lines?

- What explains any distorted incentives?
- What can regulators do to eliminate them?

15. What are the line-extension policies of different gas utilities in your state?

- Do utilities have similar policies, or do they differ?
- What are the positive and negative features of each?

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TAB 12

Canadian Radio-television and Telecommunications Commission

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> Telecom Decision CRTC 96-6

Telecom Decision

Ottawa, 7 August 1996

Telecom Decision CRTC 96-6

REGULATORY FRAMEWORK FOR THE INDEPENDENT TELEPHONE COMPANIES IN QUEBEC AND ONTARIO (EXCEPT ONTARIO NORTHLAND TRANSPORTATION COMMISSION, QUÉBEC-TÉLÉPHONE AND TÉLÉBEC LTÉE)

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OVERVIEW

(Note: This overview is provided for the convenience of the reader and does not constitute part of the Decision. For details and reasons for the conclusions, the reader is referred to the various parts of the Decision.)

On 26 April 1994, as a result of the Supreme Court of Canada's decision in Attorney-General of Quebec et al. v. Téléphone Guèvremont Inc., the independent telephone companies (the independents) in Canada were brought under the Commission's jurisdiction.

In May 1994, the Commission hired two consultants to review the regulatory regimes for the independents in Ontario and Quebec and to provide recommendations on how to facilitate the transition from provincial to federal jurisdiction. The consultants engaged were Mr. Willie Grieve with respect to the Ontario independents and the late Mr. Jean-Pierre Mongeau with respect to the Quebec independents. The consultants filed their final reports with the Commission on 30 September 1994.

In the proceeding leading up to this Decision, the Commission examined a number of issues to determine the regulatory framework for the Ontario and Quebec independents subject to this Decision. Notwithstanding the multiplicity of issues, the Commission has established for the independents the minimum regulatory intervention necessary while (i) providing an opportunity for complaint and review when warranted and (ii) complying with the requirements of the Telecommunications Act. The regulatory framework set out herein for these small companies is a lighter form of regulation than that in place, for example, for Stentor-member companies and, in some cases, is a lighter form of regulation than that proposed by the companies themselves.

In this Decision, the Commission, among other things:

- (1) found that a streamlined incentive form of earnings regulation, with minimal filing requirements, was appropriate for the Ontario and small Quebec independents, including the Public Utility Companies other than the Cochrane Public Utilities Commission (Cochrane);
- (2) approved a rate of return on average common equity for the small Quebec independents in the range of 11% to 13% and increased the width of the return ranges for the Ontario independents to 200 basis points;

(3) approved, effective 1 January 1997, a competitive interexchange regime in the territories of all the independents in Ontario and Quebec, except Abitibi-Price Inc. (Abitibi-Price), Cochrane and Northern Telephone Limited, based on the terms and conditions established in Competition in the Provision of Public Long Distance Voice Telephone Services and Related Resale and Sharing Issues, Telecom Decision **CRTC 92-12**, 12 June 1992 and Review of Regulatory Framework, Telecom Decision **CRTC 94-19**, 16 September 1994, subject to certain modifications;

(4) expressed the preliminary view that the independents should implement annual increases of \$2.00 per month per local access line effective 1 January in each of the years 1997 and 1998, in order to reduce their individual contribution requirements;

(5) approved the use of company-specific contribution rates, effective 1 January 1997, for the independents other than Abitibi-Price and Cochrane;

(6) stated its intention to issue a public notice to determine the terms and conditions for local competition in the territories of all the independents but not until a decision has been issued with respect to the terms and conditions of local competition in the territories of the Stentor-member companies;

(7) found that economic studies would not be required for tariff filings for market trials or promotions but would be required under specified conditions for other tariff filings, such as new services or rates;

(8) made a determination to forbear with respect to the sale, lease and maintenance of terminal equipment but not with respect to terminal equipment provided to two-party, four-party or multi-party services, and inside wiring;

(9) approved, for the establishment of new Extended Area Service links, the Bell Canada (Bell) criteria modified by the one dollar voting rule for use by the Ontario independents and the criteria in place for Québec-Téléphone and Télébec Itée for use by all the small Quebec independents;

(10) directed that issues pertaining to quality of service for those independents with less than 25,000 Network Access Service lines be addressed via a complaints procedure;

(11) approved the use of Bell's Terms of Service, allowing for minor variations;

(12) approved, except for certain required revisions, the Phase III Costing Manuals and procedures filed by the independents, and approved on a final basis the Ontario Telephone Association and the Association des Compagnies de Téléphone du Québec Phase III Manuals and procedures;

(13) directed those independents offering cellular services through a division of a company that provides monopoly telephone services to either, as indicated in Regulation of Wireless Services, Telecom Decision **CRTC 94-15**, 12 August 1994 (Decision 94-15), submit a proposal for forbearance, or comply with the safeguards in Cellular Radio - Adequacy of Structural Safeguards, Telecom Decision **CRTC 87-13**, 23 September 1987 and Rogers Cantel Inc. v. Bell Canada - Marketing of Cellular Service, Telecom Decision **CRTC 92-13**, 29 June 1992; and directed any telephone company offering cellular services through a separate affiliate and which is requesting forbearance to file such a request under the terms and conditions established in Decision 94-15; and

(14) accepted the continuation of the current method of regulation for Abitibi-Price and Cochrane, i.e., the traditional settlement agreement between these companies and the Ontario Northland Transportation Commission (ONTC), until the Commission carries out a separate proceeding for ONTC as noted in Regulatory Framework for the Independent Telephone Companies in Quebec and Ontario (Except Ontario Northland Transportation Commission), Telecom Public Notice **CRTC 95-15**, 23 March 1995.

I INTRODUCTION

On 23 March 1995, the Commission issued Regulatory Framework for the Independent Telephone Companies in Quebec and Ontario (Except Ontario Northland Transportation Commission), Telecom Public Notice **CRTC 95-15** (Public Notice 95-15), initiating a proceeding to deal with the regulatory framework for the independent telephone companies (the independents) in Ontario and Quebec, with the exception of the Ontario Northland Transportation Commission (ONTC).

The Commission outlined, in Appendix I to Public Notice 95-15, the key features of a suggested regulatory framework for the Ontario and Quebec independents. For Québec-Téléphone and Télébec Itée (Télébec), the Commission proposed and decided to use the same basic framework that applies to the Stentor Resource Centre Inc. (Stentor) member telephone companies under the Commission's jurisdiction (see Regulatory Framework for Québec-Téléphone and Télébec Itée, Telecom Decision **CRTC 96-5**, 7 August 1996 (Decision 96-5)). In addition, the Commission set out in Appendix II to Public Notice 95-15 a number of issues related to the municipal telephone companies.

The following were made parties to this proceeding: Association des Compagnies de téléphone du Québec inc. (ACTQ); Ontario Telephone Association (OTA); the Ontario independents - Abitibi-Price Inc. (Abitibi-Price), Amtelecom Inc., Brooke Telecom Co-operative Limited, Bruce Municipal Telephone System (Bruce), Cochrane Public Utilities Commission (Cochrane), Coldwater Communications Inc., Dryden Municipal Telephone System (Dryden), Durham Telephones Ltd., Gosfield North Communications Co-Operatives Limited, Hay Communications Co-operative Limited, Huron Telecommunications Co-Operative Limited, Hurontario Telephones Limited, Keewatin Municipal Telephone System (Keewatin), Kenora Municipal Telephone System (Kenora), The Lansdowne Rural Telephone Co. Ltd., Manitoulin Tel Inc., Mornington Communications Co-operative Limited, North Frontenac Telephone Corporation, North Norwich Telephones Limited, North Renfrew Telephone Co. Ltd., Northern Telephone Limited (Northern), Otonabee Telephones Ltd., South Bruce Rural Telephone Company Ltd., People's Telephone Co. of Forest Ltd., Quadro Communications Co-operative Inc., Roxborough Telephone Company Limited, Thunder Bay Telephone (Thunder Bay), Tuckersmith Communications Co-operative Limited, Westport Telephone Co. Ltd., and Wightman Telephone Ltd.; and the Quebec independents - Co-op de téléphone de Valcourt, La Cie de Téléphone de Courcelles Inc., La Compagnie de Téléphone de Lambton Inc., La Compagnie de Téléphone de St-Victor (St-Victor), La Compagnie de Téléphone Upton Inc., La Compagnie de Téléphone de Warwick, Le Téléphone de St-Liboire de Bagot Inc., Le Téléphone de St-Éphrem Inc. (St-Éphrem), La Corporation de Téléphone de la Baie (1993), Québec-Téléphone, Télébec, Téléphone Guèvremont Inc. (Guèvremont), Téléphone Milot Inc., Compagnie de Téléphone Nantes Inc. and Sogetel Inc. (Sogetel).

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The following parties (interveners) participated in this proceeding: l'Association des câblodistributeurs du Québec Inc., Bell Canada (Bell), CF CABLE TV Inc., Cogeco Cable Canada Inc., FONOROLA Inc. (FONOROLA), Gouvernement du Québec -Ministère de la Culture et des Communications, London Telecom Network, Mr. Gilles A. Marion, Northern Cable Holdings Limited, Ontario Hydro, Ontario Northland Telecommunications (ONT), a division of ONTC, Public Interest Advocacy Centre (PIAC), Rogers Cantel Inc. (Cantel), Sprint Canada Inc. (Sprint) and Unitel Communications Company (Unitel) (formerly Unitel Communications Inc.).

II METHOD OF REGULATION

The method of regulation for (i) the Ontario independents, excluding the municipally-owned companies (i.e., the Public Utility Companies) and Abitibi-Price, and (ii) the Quebec independents, excluding Québec-Téléphone and Télébec, is set out in Section A.

The method of regulation for five (of the six) Public Utilities Companies (PUCs) i.e., Bruce, Dryden, Keewatin, Kenora and Thunder Bay is set out in Section B. The method of regulation for Abitibi-Price and Cochrane (a PUC) is set out in Section C.

A. Regulation of Ontario and Quebec Independent Telephone Companies

1. Rate Regulation

The Ontario independents and the small Quebec independents are presently regulated on a rate of return basis. In Public Notice 95-15, the Commission suggested a form of price cap regulation for the independents. The Commission noted the workload that regulation could impose, particularly on the smaller independents and stated its desire to minimize this burden. Further, the Commission stated that, although it suggested a regulatory model in Public Notice 95-15, it was prepared to consider other models that might be more appropriate.

ACTQ did not support a price cap method of regulation for the Quebec independents, submitting that there is no simple price cap model that can be applied to companies of such varied sizes as the small Quebec independents, and that the cost and effort required to implement price cap regulation could not be justified.

OTA considered the implementation of a price cap regime inappropriate for regulating the independents because of the small size of the companies and the geographic territory they serve.

The Commission notes that the rates for local service do not reflect the cost of providing that service in the territories of the independents. Recognizing that the benefits of price cap regulation are best achieved when rates are closer to costs and that some type of earnings regulation is required until that time, the Commission finds that earnings regulation continues to be appropriate for the Ontario independents and small Quebec independents and that this method of regulation will continue for the foreseeable future.

As an alternative to price cap regulation, both ACTQ and OTA proposed forms of rate base/rate of return regulation.

ACTQ proposed an incentive earnings method of regulation that would tie an independent's actual rate of return on average common equity (ROE) to the company's variation in expenses compared to the average variation of all the Société d'Administration des Tarifs

OTA proposed an incentive-based revenue requirement methodology which included among other things:

- the use of a rate of return that is 50 basis points below the midpoint of the allowed range in determining the contribution requirement within the context of the annual filing of the CAT;
- control guidelines on operating expenses and Average Net Investment Base (ANIB); and
- a deferral account to track certain specific variances in revenues and expenses which either cause the company to exceed the upper limit of the rate of return range or fall below the lower limit of the allowed range.

Bell submitted that ACTQ had not established any link between the required ROE and, either the growth of Network Access Service (NAS) lines, or the growth of expenses compared to other members of ACTQ and that therefore ACTQ's proposal should be rejected. Bell also submitted that the ROEs of the independents should not be guaranteed through carrier contribution or any other mechanisms.

With respect to OTA's proposed control guideline for operating expenses (inflation rate + NAS growth), Bell argued that the increase in NAS may bear no direct relationship to expense.

Bell recommended that, as long as the independents were not subject to price cap regulation, parties be given the opportunity to take part in the review of the annual budgets, construction programs and Phase III procedures of these companies. This view was shared by ONT.

With respect to OTA's proposal, PIAC submitted that the 50 basis point reduction in the initial rate of return could be offset in all years through a one-time productivity gain of 3%. PIAC submitted that it would be more appropriate to include a 3% productivity gain in the operating expense control guideline.

The Commission agrees with OTA that it is not appropriate to compare the costs of Local Exchange Carriers (LECs) (i.e., those independents that provide only local exchange service) to one another without consideration of each company's size and state of technological advancement. In addition, the relationship between the expense increase of a company to that of a group of companies may not address its efficiency.

The Commission notes the concerns of Bell and ONT with a regulatory regime that does not provide for an independent review of budgets and construction programs, particularly because it is primarily these companies that, through the contribution rate, would pick up any shortfall between local rates and the revenue requirement. However, recognizing the size of the Ontario and small Quebec independents, the Commission favours as light a form of regulation as possible, while providing an opportunity for complaint and review when warranted.

With respect to OTA's proposed guidelines, the Commission agrees with ONT that OTA failed to show, in most cases, that the implementation of the proposed guidelines would provide the independents with adequate incentive to improve their productivity. Further, the Commission considers that these guidelines may be arbitrary in the sense that they highlight only operating expenses, revenues and ANIB for potential review, while leaving out other components of revenue requirement, such as depreciation and interest expense, that may from time to time require study.

The Commission considers that a carrier would only be required to explain and justify its revenue requirement forecast and associated proposed contribution rate when the contribution requirement, net of the impact of any planned and/or approved local rate increases for the year in question, exceeds the previous year's approved contribution requirement (for details regarding the information to be filed and the timing of the company filings, see Part V, Section F of this Decision).

The Commission intends generally, subject to interventions or complaints, to accept revenue requirement forecasts and proposed contribution rates that meet the contribution requirement criterion described above.

As suggested by OTA, the Commission is of the view that the revenue requirement forecast should target a rate of return 50 basis points below the midpoint of the approved range. The Commission considers that the criterion identified above for the explanation and justification of the proposed contribution rate, used in conjunction with an appropriate return range and deferral account for earnings above the maximum allowed return, as described below, provides a regulatory regime which is adequate and not burdensome.

Accordingly, commencing in 1997, the Ontario and Quebec independents are directed to:

- (a) use a rate of return 50 basis points less than the midpoint of the approved range when

(b) provide explanations and justification supporting their revenue requirement forecasts and CAT calculations if, after netting out the impact of local rate increases as discussed above, the contribution requirement exceeds the previous year's approved contribution requirement.

2. Financial Issues

In the suggested regulatory framework set out in Public Notice 95-15, the Commission noted that if a transition period is found appropriate (in the event the Commission were to move to reliance on a form of price cap regulation), the return ranges for both the Ontario and small Quebec independents would be based on their existing allowed rates of return. Further, the ranges would be widened to 200 basis points. For the Quebec independents, the Commission proposed a maximum ROE of 13% as the top of the new 200 basis point range, to be consistent with the maximum ROE of 13% ratified by the Commission for the small Quebec independents in Telecom Order CRTC 95-186, 17 February 1995 (Guèvremont's maximum ROE was set at 13% in Telecom Order CRTC 95-895, 11 August 1995).

In conjunction with its incentive-based earnings method of regulation, ACTQ proposed a 400 basis point ROE range, whereby the low end of its proposed range would be the midpoint of Bell's approved ROE range. ACTQ considered this to be appropriate because its members and Bell operate in the same geographical territory and are subject to similar variations.

OTA proposed that a methodology similar to that adopted by the Ontario Telephone Service Commission (OTSC) (in OTSC Order No. 5416) should be put in place to determine the Benchmark Cost of Equity and allowed rate of return ranges for each of the Ontario independents. OTA was of the view that the calculation of the Benchmark Cost of Equity could be done every three to five years or when circumstances dictated an earlier review.

OTA supported a 200 basis point rate of return range for its member companies, because it would provide the independents with an opportunity to be compensated for the higher risks inherent in serving the rural, remote and high-cost areas which predominantly make up their operating territories.

Bell submitted that both the ROEs and capital structures of the independents should be in line with prevailing industry norms. Bell further submitted that, for those companies which have capital structures that differ from the industry norm, differences in common equity ratios could be translated into rate of return differentials.

In reply, ACTQ stated that it recognized that it may be reasonable to use common equity ratio differentials to adjust the ROE of the Quebec independents, provided the companies' business risks are reasonably comparable. However, ACTQ proposed further fine-tuning to take into account the distinctive nature of the independents compared to the Stentor-member companies.

OTA disagreed with Bell's proposal to adjust the independents' ROE ranges according to the prevailing industry norm for telephone companies. OTA stated that the evidence being relied upon by Bell in reaching its conclusions appears to be based on industry data for only the Stentor companies, and that any comparison between the Stentor-member companies and the independents is not meaningful because of major differences in size, market demographics, cost factors and access to capital to finance telephone company operations.

In the Commission's view, there is insufficient justification for widening the independents' ROE range to 400 basis points or for tying the ROE for independents to Bell's ROE as suggested by ACTQ. A 200 basis point range, with the regulatory method established herein by the Commission, should provide the carriers with a reasonable opportunity to be rewarded if they are efficient, while minimizing regulatory burden.

The Commission agrees in principle with Bell's concern that the capital structures of the independents are not in line with prevailing industry norms and with its suggestion that these differences can be translated into ROE differentials. Similarly, the Commission considers that ACTQ's suggestion that the ROE for companies with equity ratios above 70% or below 50% be adjusted downward and upward, respectively, has merit. However, the Commission considers these adjustments to be unnecessarily complicated for the small Quebec independents to implement at this time, due to their size. In the case of the Ontario independents, the Commission notes that the allowed rate of return ranges for those companies, as established by the OTSC, already take into account, among other things, their individual capital structures. Accordingly, no adjustment for this factor is required for the Ontario independents at this time.

With respect to OTA's request to establish a procedure to determine a Benchmark Cost of Equity on a regular basis, the Commission considers that such a procedure is not warranted and would needlessly add to the regulatory burden of the independents, given that an independent telephone company can file an application with the Commission to change its rate of return range at any time. In the Commission's view, the current ranges for the investor-owned companies (as modified above) serve as an appropriate starting point for the

implementation of the regulatory framework approved for the independents.

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The Commission notes that the subscriber-owned companies (now incorporated as co-operatives) were not allowed a return on capital by the Ontario Telephone Act and considers that return ranges for these companies should now be determined. The Commission notes that, in the context of its 1995 CAT filing, OTA assumed for these companies a rate of return which corresponded to the average of the allowed rates of return on average capital for the PUCs. The Commission is of the view that, for the purposes of this proceeding, a return range for the co-operatives set at the average of the ranges established for the PUCs would be a reasonable proxy.

In view of the foregoing, the ROE range for the small Quebec independents is set at 11% to 13%. The return ranges for the Ontario independents are widened to 200 basis points. The approved return ranges for the Ontario independents are listed in Appendix I to this Decision.

3. Deferral Accounts

The Commission notes that ACTQ and those Quebec independents that commented on this issue were not opposed to the use of a deferral account, particularly in view of the fact that deferral accounts for excess earnings were established for the Quebec independents while under the jurisdiction of La Régie des télécommunications du Québec (La Régie).

OTA, on the other hand, proposed that a deferral account be set up to track certain specific variances in revenues and expenses which either cause a company to exceed the upper limit of the allowed rate of return range or fall below its lower limit. Under OTA's proposal, these amounts would be recorded on an annual basis and tracked over a five-year period.

The Commission considers that a deferral account to record any excess earnings is a regulatory tool that can complement the earnings regulation method established above.

The Commission rejects, however, OTA's proposed deferral account because it would be burdensome and the proposal to track certain specific variances in revenues and expenses does not serve the purpose of recording excess earnings for ultimate redistribution. Rather, the Commission directs the Ontario independents to record, as of 1997, and the Quebec independents to continue to record, in a deferral account, any earnings in excess of their respective maximum approved rates of return.

As local rates are below cost and revenues from the contribution rate recover this shortfall, the Commission considers that any amounts recorded in these accounts commencing in 1997 should be refunded to the various long distance carriers on a pro-rata basis, i.e., based on their share of total minutes carried in the year. The refund would be required to be remitted within three months after year end. An independent which cannot meet the three-month deadline may, up to 60 days before year end, apply to the Commission for an extension of this time limit. This refund procedure shall commence with any excess earnings generated in 1997.

With regard to balances in deferral accounts, accumulated to 31 December 1994, the Commission directs that, by 7 October 1996, each company with such a balance submit a plan for the disposition of the funds to the Commission. The Commission, on a preliminary basis, is prepared to approve plans that would apply the funds to the improvement of basic local service.

For any excess earnings deferred in 1995 and 1996, the Commission directs that, by 7 October 1996 and 30 June 1997, respectively, each company with such a balance submit a proposal for the disposition of the funds. The Commission favours a pro-rata refund to long distance carriers for 1995 and 1996, due to the existence of a contribution component in the CAT for these years. Under such an arrangement, excess earnings likely reflect a contribution rate that was higher than required. Companies are required to justify why the deferred amounts should not be refunded in the manner suggested above by the Commission.

4. Financial Filing Requirements

Given the method of regulation approved above, the Commission finds acceptable ACTQ's proposal that audited financial statements should be filed by 31 March of each year. This is consistent with Telecommunications Fees Regulations, 1995, Telecom Public Notice **CRTC 95-20**, 25 April 1995, wherein the Commission stated that it expects carriers to file their most recent annual financial statements on or before 31 March of each year.

Although the Commission does not consider pro-forma financial statements necessary, forecast financial information supporting the calculation of the proposed CAT will be required when the independents submit their CAT application each year (refer to Part V of this Decision). As noted in Part II, Section A under "Rate Regulation", explanations and justification of the proposed contribution rate will not normally be required if the independents meet the criterion outlined in this Decision.

With respect to capital expenditures, in order to reduce the regulatory burden on the independents, there will be no formal filing requirements. Rather, the need for further

information will be assessed on a case-by-case basis (e.g., to assess the reasonableness of any significant broadband initiatives, or in response to a complaint). With respect to depreciation, consistent with the Commission's Phase I directives, the maximum interval between depreciation studies for the independents should be five years. The Commission finds reasonable OTA's suggestion that its members file, annually, any change to its depreciation life characteristics.

In addition, each of the independents is required to notify the Commission, as necessary, of any major changes to its accounting policies.

B. Regulation of the Public Utility Companies Excluding Cochrane Public Utilities Commission

Five (of the six) PUCs in Ontario, namely Bruce, Dryden, Keewatin, Kenora and Thunder Bay, jointly proposed a regulatory model based on a social contract form of regulation whereby the Commission would forbear from exercising powers or performing duties under various sections of the Telecommunications Act (the Act) and would essentially regulate by responding to complaints.

The Commission is of the view that the proposed forbearance-based social contract form of regulation proposed by the PUCs cannot be adopted at this time. The proposed regime would increase the likelihood of cross-subsidization of competitive services and increase the potential of the PUCs to price their competitive services below cost with the effect of impeding the establishment and continuance of competitive markets and would therefore be contrary to subsection 34(3) of the Act.

The Commission finds the band-pricing concept proposed by the PUCs to be inconsistent with the Commission's policy of moving rates towards costs. The Commission considers such a policy important in that it sends the proper economic signals and promotes the efficient entry of competitors into telecommunications markets, in keeping with the policy objectives of the Act.

The Commission concurs with the concerns raised by FONOROLA, Sprint and Unitel that the PUCs' proposed formula for determining the contribution component of the CAT would potentially lead to a contribution rate that would not be just and reasonable for toll carriers and the customers of such toll carriers.

The Commission is of the view that, with the evolving competitive environment in telecommunications and the multiplicity of players in that market, there are interests which extend well beyond the confines of local concerns and matters such as competitive safeguards should not be under the sole purview of the local service provider.

The Commission also notes that the absence of tariff regulation for monopoly services would create a regulatory environment where it would be difficult to determine if unjust discrimination exists.

Therefore, the Commission concludes that the regulatory framework to be applied to the PUCs (except Cochrane) should be identical to that specified for all Ontario independents, giving all subscribers equivalent safeguards under the Act and equivalent access to competitive telecommunications services. Applying the identical regulatory regime to the PUCs will create a single framework for all independents in Ontario and will make that regulatory framework consistent with the policy objectives of the Act.

The Commission notes that issues particular to municipal ownership, such as the PUCs' income-tax-exempt status, do not represent an impediment to rate-of-return regulation. In the Commission's view, the policy of moving rates towards cost while not imputing income-tax expenses to the rate calculations will have the effect of passing the benefit of the income-tax-exempt status to all ratepayers and thus not deprive the PUCs' subscribers of the main benefits of municipal ownership.

The Commission also notes that prior to coming under the Commission's jurisdiction, the PUCs were regulated by the OTSC, which applied an imputed capital structure and a return on average capital range for each of the PUCs to emulate investor-owned companies. The Commission considers that the PUCs' differing capital structures and lower cost of debt were appropriately reflected in the OTSC's rate of return on average capital mechanism. The Commission does not foresee any difficulty in continuing to apply such a regime.

Further, the rate of return on average capital ranges employed by the OTSC will be widened to 200 basis points. In reaching this conclusion, the Commission does not agree with OTA's suggestion that the PUCs' allowed ranges should be narrower due to a relatively lower risk. The approved return ranges for the PUCs are set out in Appendix I to this Decision.

As described above for the other independents, the PUCs will be required to record any excess earnings in a deferral account and file limited financial information. As well, the PUCs will be required to use a rate of return 50 basis points below the midpoint of their approved range when determining the CAT and would only be required to provide explanations and justification supporting the CAT filing under the conditions described in Part II, Section A for

**C. Regulation of Abitibi-Price Inc. and
Cochrane Public Utilities Commission**

As part of its initial submission of 23 May 1995, OTA noted that Cochrane and Abitibi-Price had provided additional comments relating to their individual circumstances, but that their comments were intended to supplement OTA's submission on the regulatory framework for the Ontario independents, which was filed on behalf of all its members.

Cochrane noted that it is unique in that it is operated as a department within the operation of a public utilities commission. Cochrane, noting that it consists of four departments: electric, water, sanitary sewer and telephone, submitted that it requires time to ensure that its records allow for an accurate costing process. In addition, Cochrane stated that local rates should be approved by the locally-elected Commissioners, arguing that they represent the customers who elected them, and that therefore there is no incentive to abuse the subscribers as in a monopoly. Cochrane stated that the role of the Commission should be that of regulator of last resort. In Cochrane's view, the Commission should not duplicate the efforts of locally-elected officials representing the best interests of the ratepayers.

Cochrane recommended, among other things, that the Commission (1) recognize the uniqueness of every telephone company in making its final decision in this proceeding; (2) forbear from regulating Cochrane's local and cellular services; and (3) ensure that local rates are not forced up by regulation, but change through the evolution of the industry.

Abitibi-Price stated that it operates its Mill Business Unit as several businesses (newspaper, telephone, power, etc.); however, that there is only one asset ledger. Abitibi-Price stated that it would need time to separate all assets related to telephone operations. Until that process is completed, Abitibi-Price argued that it should be excluded from the CAT.

No specific comment was received from Cochrane or Abitibi-Price on the issue of widening their respective ROE ranges.

The Commission recognizes the unique circumstances facing Abitibi-Price and Cochrane, and accepts the continuation of the current method of regulation for Abitibi-Price and Cochrane, i.e., the traditional settlement agreement between these companies and ONTC until the Commission carries out a separate proceeding for ONTC as noted in Public Notice 95-15. In view of this, and the fact that these companies do not presently have separate telephone company records, but rather are operated as separate divisions, Abitibi-Price and Cochrane will not be required to file forecast CAT and associated supporting financial information as is the case for the other OTA members. However, the Commission requires these two companies to continue to file financial statements by 31 March following each fiscal year.

Issues related to capital expenditure and depreciation filings, Commission notification of any major changes to these companies' accounting policies, and the appropriate width of their respective ROE ranges will be dealt with when the Commission carries out the separate proceeding for ONTC noted above.

**III INTEREXCHANGE COMPETITION AND
RELATED ISSUES**

A. Interexchange Competition

1. General

The Commission notes that parties were generally in favour of the competitive regime proposal set out in Public Notice 95-15.

The Commission is of the view that resellers and interexchange carriers (IXCs) should be allowed to compete in the territories of the independent companies which are subject to this Decision. Accordingly, the Commission approves, effective 1 January 1997, a competitive interexchange regime in the territories of all the independents in Ontario and Quebec, except Abitibi-Price, Cochrane and Northern, based on the terms and conditions established in Competition in the Provision of Public Long Distance Voice Telephone Services and Related Resale and Sharing Issues, Telecom Decision **CRTC 92-12**, 12 June 1992 (Decision 92-12) and Review of Regulatory Framework, Telecom Decision **CRTC 94-19**, 16 September 1994 (Decision 94-19), subject to the modifications detailed below. These modifications are necessitated by the uniqueness of the independents with respect to serving areas, services offered, size and/or ownership arrangements.

IXCs and resellers are required to register with the Commission and with the telephone companies in whose territories they intend to operate. IXCs and resellers are to be prepared, if requested to do so by the telephone company in question, to provide pertinent traffic statistics that may be required for billing purposes and for calculating the CAT rates.

2. Application of the Carrier Access Tariff

Traditionally, Bell has made the independents in Ontario and Quebec financially whole, previously through the use of a revenue sharing agreement and more recently through the

establishment of a CAT which is applied to all switched voice and data traffic. In Quebec, the CAT is also applied to non-switched traffic. The Commission notes that the existing contribution charges for the independent telephone companies are significantly higher than the contribution charge for Bell. The Commission is of the view that there is merit, therefore, in recovering the local/access shortfall from as much traffic as possible in order to reduce the per-minute contribution rate. However, the Commission has concerns with the existing agreement between Bell and the independents in Quebec whereby contribution is paid on all traffic, including traffic that is not switched on the Public Switched Telephone Network (PSTN). The Commission considers that such an arrangement could have a negative impact on competitors when determining their optimal network configuration. To the extent that competitors make use of dedicated facilities to provide point-to-point services, this should be permitted without the competitors having to pay contribution. Accordingly, the Commission is of the view that contribution should be paid on all switched voice and data traffic that is interconnected to the PSTN.

With respect to the collection of contribution from interexchange competitors, the Commission is concerned with contribution being paid twice on services which are being resold. Therefore, where an independent already collects contribution on the underlying resold services used by a reseller to carry traffic, that reseller need not pay contribution to originate and/or terminate traffic in that independent's operating territory.

Accordingly, the Commission approves the payment of contribution on all interexchange public switched voice and data traffic that is interconnected to the PSTN. Canadian carriers providing wireless services are not required to pay contribution on such services. Where a reseller resells switched long distance services for which contribution is paid, those resold minutes will be exempt from contribution. Competitors are to make use of the existing Commission contribution exemption process for situations where they are not required to pay contribution on their traffic.

3. Adjustments to the Carrier Access Tariff - Contribution Discounts and Direct Access Line Loading Factors

The Commission is of the view that, at this stage in the development of the interexchange market, the existing IXCs are well established and that discounts are not necessary to promote competition in the territories of the independents. With respect to resellers, the Commission is of the view that a 15% discount is appropriate for line-side access in the territories of all the independents in light of the inferior quality of this service.

In order to achieve the Commission's stated objective of reducing the contribution rate by recovering contribution from as much traffic as is reasonable, the Commission is of the view that all switched traffic, including stimulated traffic minutes, should be included in the contribution rate calculation.

With respect to the treatment of Direct Access Lines (DALs), the Commission is of the view that since the appropriate means to apply the contribution mechanism is based on a per-minute charge, it is appropriate to impute a usage figure for DALs as is currently done by the OTA and ACTQ in their contribution rate calculations. The imputed figure for DALs is included in the total minute count of switched interconnected traffic. With respect to the proxy figure to use, the Commission is of the view that 8,000 minutes per month per DAL, as is currently used in the agreements between Bell and the independents, is a reasonable approximation at this time.

B. Equal Access

The competitive regime established by the OTSC in Ontario, and the interim competitive regime established by the Commission in Quebec, did not address the issue of equal access. While parties were in support of providing equal access, there were differing views with respect to the timing of its implementation and the responsibility for recovering the associated cost.

The Commission is of the view that equal access is important to encourage the spread of competition and that it should be implemented where technologically feasible (as per Decision 92-12). As well, the Commission notes that equal access can be achieved in certain cases through the Bell toll switch serving the independent territory, with a probable reduction in the independent's cost of implementing equal access. Accordingly, by 1 January 1998, the independents are directed to implement equal access, defined as Feature Group D with CCS7 signalling, where technologically feasible. Each independent is to file an equal access roll-out plan with the Commission by 1 January 1997, indicating in which exchanges equal access will be implemented and by what date. For those exchanges that will not be converted by 1 January 1998, the independent is to provide a reason why equal access will not be implemented by that date and when it is expected to be.

Further, the Commission is of the view that it is necessary to establish Primary Interexchange Carrier (PIC) and Customer Account Record Exchange (CARE) procedures similar to those established for Stentor-member companies, prior to the implementation of equal access. The Commission will not require the independents to establish a Carrier

Services Group, as long as these companies do not offer long distance service themselves. The independents are directed to establish a PIC/CARE process prior to implementing equal access. All companies are directed to file by 1 August 1997, for approval, the appropriate tariffs and a PIC/CARE Access Customer Handbook associated with the PIC/CARE process.

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IV RATE ADJUSTMENTS

The Commission notes that, with the introduction of competition in Bell's operating territory, subscribers of all the independent telephone companies have benefited from lower rates for long distance services as well as from the availability of alternative providers of long distance service in some independents' territories.

The Commission notes that there has been no pressure to increase the local rates of the independents because the financial viability of these small companies (1) has in the past been ensured by the revenue settlement process with Bell and (2) is currently ensured through the independents' CAT.

The Commission agrees with parties that local rates will need to be more reflective of underlying costs, particularly if there is to be effective local competition. Further, the Commission considers that rate increases are necessary to reduce the individual contribution requirements of the independents. The Commission notes, however, that those parties supporting local rate increases did not comment on the level and timeframe for implementing such increases.

The Commission is of the preliminary view that the independents, including the PUCs, should be required, like the Stentor-member companies, to increase their local rates by a total of \$4.00 per month in two stages. The \$4.00 per month increase per subscriber being proposed would not be required in those cases where an independent's contribution requirement has been reduced to zero or where a particular local rate is already compensatory.

Accordingly, the Commission is of the preliminary view that annual increases of \$2.00 per month per local access line should be implemented by the independents effective 1 January in each of the years 1997 and 1998. In order to allow public input on this preliminary view, the companies are directed to notify subscribers, through a billing insert, of the proposed local rate increases and to outline the procedures to be followed by subscribers who wish to comment and for company replies. The companies are directed to file the proposed text of the billing insert by 23 August 1996. The Commission encourages the independents to file, where applicable, one billing insert through their respective associations. The companies are directed to file, by 1 September 1996, proposed tariff pages for local rate increases that are consistent with the above, to take effect 1 January of each of the years 1997 and 1998. The companies are also directed to distribute the billing inserts to their subscribers by 30 September 1996. Following an assessment of comments received, the Commission will make its final determination.

V TOLL REVENUE SETTLEMENT MECHANISM

A. Contribution Charge

In its 23 May 1995 submission, OTA proposed an OTA Blended CAT, whereby a single contribution rate would be established for the Ontario independents and Bell, effective 1 January 1996. OTA subsequently revised its proposal to include the Quebec independents. The revised Blended Cat would be collected on an industry-wide basis and distributed to the independents through funds administered by their respective associations. ACTQ proposed a single contribution rate for the Quebec independents based on the blending of their contribution rates.

The Commission notes that industry-wide contribution rates, as suggested by OTA and ACTQ, would average the net local/access shortfalls across all independents, even though the revenues and cost structures of these companies vary widely. Consequently, any form of an industry-wide contribution rate would be an average which would not be representative of the operational performance of any of the independents. Hence, the link between an independent's cost of providing local service and its contribution rate would be broken, resulting in low-cost areas subsidizing high-cost areas. This would be contrary to the Commission's principles of making rates more reflective of costs and of fostering an environment in which local and long distance service providers can compete.

Further, the Commission considers that any management decision made by an independent regarding revenues or costs would be directly reflected in a company-specific contribution rate (as opposed to being lost in a blended contribution rate). Consequently, the company-specific contribution rate would serve as a "barometer" of company performance vis-à-vis revenues and costs, as well as reflect the real economic conditions within which prospective alternative toll providers would compete.

In light of the above, the Commission concludes that the most appropriate method of settling contribution payments between the independents and their toll providers is through company-specific contribution rates. This will ensure cost-based rates, eliminate the

possibility of cross-subsidization, make the contribution rates "barometers" of the real operational performance of the independents and ensure that prospective toll competitors are given realistic economic signals regarding the competitive environment in the independents' territories. Accordingly, the Commission directs that company-specific contribution rates be implemented starting 1 January 1997.

Further, the Commission is of the view that no true-up provisions should be included in the company-specific contribution rates. The Commission notes that this would be in line with its position in Contribution Charges Effective 1 April 1993, Telecom Decision **CRTC 93-11**, 29 July 1993, where it stated that it was not in favour of making adjustments to the contribution charges during the year, except under extraordinary circumstances, and in which it adopted the contribution mechanism with the intention of keeping ongoing regulatory intervention and involvement to a minimum.

The Commission notes that the PUCs proposed a formula to use Bell-based contribution levels, combined with the proposal to implement rates within a band of 75% to 100% of the Bell-equivalent rates, for determining contribution rates specific to each PUC. However, the Commission shares a number of the concerns raised by OTA, Bell and Sprint regarding this proposal. Particularly, the Commission notes that the PUCs' formula would determine contribution rates that would not be based on the PUCs' costs. Also, the PUCs' proposal would depart from the purpose of contribution, which is to offset unavoidable revenue shortfalls resulting from the provision of access and local services. The proposal would break the relationship between the unsatisfied revenue requirement and the level of contribution.

As part of the annual CAT filings required of the independents, the annual development of forecast originating and terminating toll minutes in the territories of each of the independents will be required. The Commission is of the view that these minutes should be estimated and agreed to by both the independents and their toll providers. Also, the Commission is of the view that the collection of contribution should be based on actual toll minutes, or in the case where actual minutes cannot be obtained, on the basis of an agreed-to estimate between the independents and their toll providers.

The Commission notes that its decision does not preclude the independents' associations from doing the work associated with preparing/estimating the company-specific contribution rates and/or estimating the toll conversation minutes. However, should an independent retain the services of its association, the Commission is of the opinion that the company-specific contribution rates should reflect the costs to that independent for services rendered by its association, since these costs would have been incurred by that independent even if the task were carried out in-house.

B. Calculation of the Contribution Requirement

The Commission is of the view that a consistent approach to calculating the contribution requirement will be easier to administer.

The Commission notes that as a result of its decision to forbear from the regulation of terminal equipment (see Part VIII of this Decision), the surplus/shortfall in the Competitive Terminal Broad Service Category (BSC) should be excluded from the contribution requirement calculation.

The Commission further notes that in order to be consistent with previous decisions it has made with respect to the Stentor-members' cellular operations, it directs the independents to also exclude revenues, investment and expenses from cellular operations, including an attributable portion of common costs, from the contribution requirement calculation. Companies which provide cellular service as part of their operations are directed to provide details on the methodologies used to exclude cellular operations from the contribution and revenue requirement calculations at the time of their respective 1997 contribution filings.

Details as to the methodology to be used by the independents in Ontario and Quebec, excluding Abitibi-Price and Cochrane, in order to calculate their respective contribution requirement are set out in Appendix II.

C. Recovery of the Start-up Costs for Equal Access

To provide interconnection to the toll carriers, the independents will have to modify their networks, systems and procedures which will cause additional costs to be incurred. Start-up costs, such as the cost of modifying switches, will occur once, generally near the outset of competitive entry.

The Commission notes that the PUCs proposed to use the equal access component of the 1997 OTA CAT for the years beyond 1997. The Commission rejects the PUCs' proposal because it would result in rates which would not reflect the individual PUCs' costs but rather an average of the OTA members' costs in 1997.

The Commission notes that the independents assign to the Toll BSC the ongoing costs they incur to connect IXCs to their networks. With the implementation of equal access for the use

of IXCs and their customers, the Commission considers it reasonable for the independents to also assign the costs of implementing equal access to the Toll BSC and to provide for the recovery of those costs over a ten-year period. The Commission notes that assigning the start-up costs of equal access to the Toll BSC is different from the practices approved for Stentor-member companies which assign these costs to the Utility segment. However, the Commission finds that a single rate for the recovery of the start-up costs of equal access and switching and aggregation costs based on Phase III costs, as outlined in Section D below, will be easier for the small independents to implement because it will make use of a costing approach that is already in place.

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Accordingly, the Commission directs the small independents to assign the start-up costs of equal access to the Toll BSC and to provide for the recovery of those costs over a ten-year period.

D. Recovery of Switching and Aggregation Costs (Direct Toll Charge)

Switching and aggregation costs are ongoing costs primarily associated with aggregating and terminating competitors' traffic for delivery to and from the toll carriers' networks. Other ongoing cost components are associated with customer and operator services and carrier billing functions.

The Commission has concerns with the PUCs' proposal to use the Direct Toll component of the 1997 OTA CAT for the years beyond 1997. The PUCs' proposal would result in the Commission approving rates which do not reflect the PUCs' costs but which instead would reflect an average of the OTA CAT members' switching and aggregation costs in 1997.

The Commission is of the view that while a Phase II costing approach was used to determine switching and aggregation costs in Decision 92-12, this same approach should not be imposed on the small independents. Rather, the Commission supports the small independents' current practice of equating switching and aggregation costs to the costs they currently assign to the Toll BSC.

The Commission notes that as a result of its directive to assign equal access start-up costs to the Toll BSC (Part V, Section C of this Decision), the Toll BSC will now contain both switching and aggregation and equal access start-up costs.

The Commission notes that switching and aggregation functionality and equal access are used only by toll providers with trunk-side access to the telephone company's switch. Accordingly, the Commission is of the view that the small independents' combined charge for switching and aggregation and equal access should be calculated using originating and terminating minutes associated with trunk-side access to the switch, and should be applied only to trunk-side traffic.

The Commission directs each of the independents to file, as part of their annual CAT filing, from 1997 onwards, a single company-specific rate for the recovery of switching and aggregation and equal access start-up costs. The rate is to be calculated in accordance with the principles set out above.

E. 1995 and 1996 Carrier Access Tariffs

Details concerning the 1995 and 1996 OTA and Northern CATs are set out in Appendix III. Matters relating to the 1995 and 1996 CATs for the small Quebec independents are set out in Appendix IV.

F. Contribution Rate Filing Requirements for 1997 and Subsequent Years

With respect to the CAT-related filing requirements of the independents for 1997 and subsequent years, the Commission has endeavoured to strike an appropriate balance between the need to minimize the regulatory burden on the independents and the need for sufficient information to permit the Commission to adequately monitor the companies and ensure that rates remain just and reasonable. In so doing, the Commission is cognizant of the views of the independents that filing requirements should be kept to a minimum, taking into account their available resources and size.

For 1997 and subsequent years, the independents are directed to file for each calendar year company-specific CATs and supporting information by 31 January of the same calendar year. Until the Commission approves the company-specific CATs for each calendar year, and in order to reduce the regulatory burden on the small independents, the Commission directs that the previous year's CATs become the interim CATs for the calendar year in question. The 31 January filings are to include the supporting information for the proposed contribution rate and combined switching and aggregation and equal access charge as follows:

(1) forecasts of total originating and terminating switched toll conversation minutes, and a breakdown of that total into trunk-side and line-side traffic;

(2) budget views by BSC or equivalent; and

(3) forecast contribution and revenue requirements.

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As noted earlier, the Commission will require an independent to provide explanations and justification supporting its revenue requirement forecasts and contribution calculations if, after accounting for local rate increases as discussed in Part II, Section A, its contribution requirement exceeds the previous year's approved contribution requirement. In order to do this for the first year under the new contribution regime, the Commission will need to establish a 1996 base for comparison with 1997. Accordingly, the Commission directs the independents to file, by 31 January 1997, the following information to be based on 10 months of actuals and two months of forecast data:

(1) an estimate of 1996 total originating and terminating switched toll conversation minutes, and a breakdown of that total into trunk-side and line-side traffic;

(2) 1996 budget views by BSC or equivalent; and

(3) estimated 1996 contribution and revenue requirements.

The forecast 1996 contribution requirement will serve as the base for comparing with the applied for contribution requirements for 1997. For 1998 and subsequent CAT filings, the comparison will be made between the contribution requirement specified in the independent's current CAT filing and the contribution requirement approved by the Commission following its examination of the independent's previous year CAT filing.

VI PHASE III METHODOLOGY

A. Status and Use of Phase III Manuals and Procedures

Just after the independents were brought under the Commission's jurisdiction in April 1994, the Commission approved, in Telecom Order **CRTC 94-883**, 29 July 1994, all past Orders of the OTSC, thereby granting interim approval to the OTA Phase III costing methodology which had been granted interim approval by the OTSC.

During the course of this proceeding, ACTQ, on behalf of its members which were ACTQ CAT participants at that time, filed its proposed Phase III Manual.

The Commission notes that three OTA members, i.e., Cochrane, Abitibi-Price and Northern are not OTA CAT participants. Cochrane and Abitibi-Price did not want to use Phase III procedures, preferring instead to use their existing settlement arrangements with ONTC. Northern, on the other hand, uses the OTA Phase III procedures to derive a separate Northern CAT for its toll settlement with ONTC which was granted interim approval in Telecom Order **CRTC 95-465**, 13 April 1995.

The PUCs, except Cochrane, stated in their 13 October 1995 comments that, in order to meet contractual obligations, they would continue to participate in the OTA CAT for settlement purposes, but would not rely on the OTA Phase III methodology after 1997.

The Commission notes that three ACTQ members, Guèvremont, St-Éphrem and St-Victor are not ACTQ CAT participants. However, both St-Éphrem and St-Victor now use the ACTQ Phase III procedures.

The Commission concurs with the view of most parties that a Phase III type costing methodology should be used by all independents as the basis for calculating a CAT for each company on a consistent basis. The Commission considers that the Phase III procedures currently used by the OTA and ACTQ CAT participants as well as Northern, for CAT development purposes, generally parallel those established by the Commission for the Stentor-member companies. Except for certain revisions, the Commission finds the procedures contained in the OTA and ACTQ Phase III Manuals acceptable for use in the production of the Phase III results used to develop the CAT. Accordingly, the Commission grants final approval to the OTA and ACTQ Phase III Manuals, subject to certain revisions set out below.

The Commission is of the view that any approved change to the Stentor-members' basic Phase III costing concepts for investment and expenses should generally be adopted by the independents. In this regard, the Commission notes that with respect to the directives on switching procedures specified in Review of Phase III of the Cost Inquiry, Telecom Decision **CRTC 94-24**, 18 November 1994 (Decision 94-24), ACTQ indicated it was prepared to make the necessary changes. OTA, on the other hand, did not endorse the revised procedures and noted that different rules may be more appropriate for the Ontario independents' Phase III costing purposes.

The Commission considers that switching investment, which is a major cost component, should be assigned consistently by all telephone companies, in accordance with the switching assignment procedures specified in Decision 94-24.

The Commission also considers that a consistent format should be used by all independents

in the presentation of their actual Phase III results in order to equate the results to each company's audited financial statements. Therefore, in order to achieve consistency in the format of Phase III results, the OTA and ACTQ members as well as the PUCs which are CAT participants are directed to present their actual Phase III results in a manner that ensures the results equate to each member's audited financial statements. In particular, revenues, investment and expenses related to cellular and terminal operations are to be included in the Network and Terminal BSCs, respectively.

The Commission notes that the format requirements for the reporting of Phase III results are not intended to reflect each company's regulated rate base for the purpose of assessing revenue requirement.

The Commission also notes that the changes to the Phase III Manuals described above are to be reflected in the production of each independent's actual 1995 Phase III results. Therefore, on behalf of their members and/or CAT participants, the OTA and ACTQ are directed to file, within 60 days, updated pages to their Phase III Manuals which reflect the required changes noted above.

The Commission notes that Guèvremont has yet to file its Phase III procedures. Guèvremont is directed to advise the Commission, within 30 days of the date of this Decision, of the method it expects to use to derive a CAT and when it expects to file the supporting documentation.

With respect to the PUCs' proposal to discontinue using the OTA Phase III costing procedures to calculate a CAT after 1997, the Commission considers that any alternative proposal to replace the OTA Phase III costing methodology should be subject to a review process prior to implementation to ensure that Phase III cost causality principles are maintained.

As for the implementation of the Phase III methodology by Abitibi-Price and Cochrane, the Commission considers that their current settlement arrangements with ONTC are acceptable, pending the Commission's review of a regulatory framework for ONTC.

B. Phase III Results

As noted in Part V of this Decision, the independents will be filing forecast financial information supporting their CAT calculations at the time the CAT applications are filed. Therefore, in lieu of a detailed Phase III forecast, OTA members, the PUCs and ACTQ members, excluding Télébec and Guèvremont, are directed to file forecast financial data at a BSC level or equivalent to support the local/access shortfall on which the contribution requirement is based.

All independents, except Guèvremont, are directed to file their respective actual Phase III results, for the calendar year 1995, by 31 October 1996 and on the same date for subsequent years.

The Commission will make a determination on the applicability of the aforementioned Phase III filing requirements for Guèvremont, including the audit, update and accounting manual filing requirements set out below, once it has reviewed the company's proposed costing methodology used in deriving a CAT.

C. Other Filing Requirements

The Commission notes that the Stentor companies file updates to their respective Accounting and Phase III Manuals. The Phase III Manual updates are subject to a public process in accordance with Bell Canada and British Columbia Telephone Company - Phase III Manuals: Compliance with CRTC Telecom Public Notice **1986-54** and Telecom Order CRTC 86-516, Telecom Decision **CRTC 88-7**, 6 July 1988, as amended by Proposed Revisions to the Phase III Manual Update Procedure, Telecom Letter Decision CRTC 89-26, 1 December 1989 and by Decision 94-24.

Similarly, the Commission considers that the independents will be required to update their respective Accounting Manuals (or equivalent) and their Phase III Manuals. In this regard, each OTA and ACTQ CAT participant is directed to file with the Commission, within 30 days, one copy of the most recent edition of its Accounting Manual or equivalent (which may be filed on their behalf by their respective associations, as applicable) and to file annual updates thereafter, as necessary, coincident with the filing of Phase III Manual updates as set out below.

With respect to the filing of Phase III Manual updates by the independents, the Commission notes that, given their size, the volume of updates will be significantly lower than that required of Stentor-member companies. Furthermore, the Commission considers that a scheduled public process should only apply to toll carriers. Therefore, the Commission considers that one annual submission, filed on or before 31 March of the following calendar year, is appropriate. Interested parties may register with the Commission to receive amended pages as filed.

The Commission notes that annual audits of Phase III results are required for Stentor companies. With respect to the independents, taking into account the size of these

companies and parties' comments on this matter, the Commission considers that audits would be costly and burdensome for them. Therefore, the Commission directs that an initial review of each company's Phase III results is to be undertaken. This initial review is intended to confirm that the Phase III procedures, documented in the Phase III Manuals, are being appropriately employed to derive the Phase III results. In the Commission's view, the reviews applicable to members of OTA and ACTQ may be conducted by knowledgeable staff designated by their respective associations, as applicable, in consultation with those members which are CAT participants. The PUCs are also directed to conduct reviews on a corresponding basis. In light of the number of Phase III results to be reviewed, the Commission considers that this activity may be scheduled over the two-year period commencing 1 January 1997. Accordingly, each company is directed to notify the Commission that initial reviews have been completed when they file their actual Phase III results each year on 31 October 1997 or 1998 as applicable. Thereafter, the Commission considers that reviews may be conducted on an exception basis or as deemed necessary by the Commission.

D. Other Costing Methods

On the basis of its review of the positions taken by the PUCs, Abitibi-Price and Cochrane, the Commission maintains its support for a consistent Phase III-type costing procedure. However, the Commission considers that it may not be appropriate to expect LECs to support a full-fledged Phase III costing system, particularly if the companies are not affiliated with an association with the relevant expertise. Therefore, the Commission is of the view that in cases where it can be demonstrated that there is a need to consider alternatives, it will consider them on the basis of cost causality principles.

VII LOCAL COMPETITION

In Decision 94-19, the Commission endorsed the principle of local competition for the Stentor-member telephone companies, expressing the view that local competition will lead to benefits such as productivity improvements and the introduction of even more innovative services. Consistent with this view, the Commission, in Public Notice 95-15, proposed that local competition be permitted in the territories of all independents in Quebec and Ontario (except ONTC), noting that issues such as unbundling and co-location would have to be considered.

Most parties agreed with the Commission's proposal in principle, subject to certain concerns being addressed. Accordingly, the Commission is of the preliminary view that local competition should be allowed in the territories of the independents.

As part of a future proceeding to address local competition for the independents, the Commission will examine whether further rate adjustments would be appropriate. At that time, the Commission will have the benefit of input from the proceeding initiated by Local Service Pricing Options, Telecom Public Notice **CRTC 95-49**, 22 November 1995 (Public Notice 95-49). The Commission notes that the independents were encouraged to participate in the proceeding initiated by Public Notice 95-49.

However, the Commission notes that there is currently a proceeding underway to determine the terms and conditions of local competition as it relates to the Stentor-member telephone companies (Implementation of Regulatory Framework - Local Interconnection and Network Component Unbundling, Telecom Public Notice **CRTC 95-36**, 11 July 1995). The Commission considers that it would not be appropriate to commence a proceeding to deal with the issues of local competition in the territories of the independents until a decision has been issued with respect to the terms and conditions of local competition in the territories of the Stentor-member telephone companies. Following the release of such a decision, the Commission intends to issue a public notice to determine the applicability of those terms and conditions for local competition in the territories of the independents.

VIII TARIFF FILING REQUIREMENTS AND TERMINAL EQUIPMENT FORBEARANCE

A. Tariff Filing Requirements

The Commission notes that the Act provides that no Canadian carrier shall provide a telecommunications service except in accordance with a tariff filed and approved by the Commission. In this Decision, the Commission has set out the conditions for forbearance from the regulation of cellular services and terminal equipment provision for the independents. Therefore, for telecommunications services other than those which the Commission has determined meet the conditions for forbearance, the independents are required to continue to file tariffs, for approval, but will only be required to file economic studies (1) in support of filings for new services; (2) when proposing rates for a service that are not comparable to rates approved by the Commission for other telephone companies offering the same service; (3) for rate reductions, where there are concerns that rates may not make an appropriate contribution to the local/access shortfall; and (4) where there is a potential for anti-competitive pricing.

With respect to market trials and promotions, the independents in general requested that the Commission take a flexible approach. The Commission notes that, while tariffs will

continue to be required for these services, it is open to the consideration of market trial and promotion tariffs which provide a degree of flexibility for such offerings. Economic Studies will not be required for market trials or promotions and the Commission will also endeavour to deal with such filings on an expedited basis.

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A summary of the filing requirements for the small independents, including those relating to tariffs, is provided in Appendix V of this Decision.

B. Terminal Equipment Forbearance

The Commission agrees with ACTQ, OTA and the PUCs that a competitive environment exists with respect to terminal equipment and that regulatory oversight of the activities of the independents in this market is neither warranted nor desirable.

In Forbearance - Sale of Terminal Equipment by Canadian Carriers, Telecom Decision **CRTC 94-14**, 4 August 1994 and in Decision 94-19, the Commission made a determination to forbear, for the Stentor-member companies, with respect to the sale, lease and maintenance of the Competitive Terminal - Other (CT-O) category (single - line telephones and accessories) and the Competitive Terminal - Multiline & Data (CT-MD) equipment category (includes key systems, PBXs and data equipment). The Commission noted the concern about possible cross-subsidies from monopoly services to terminal equipment services and anti-competitive pricing. In Decision 94-19, however, the Commission noted that, once the rate base has been split, the ability of the Stentor companies to cross-subsidize or engage in anti-competitive pricing initiatives with revenues from monopoly services will be largely eliminated.

With the establishment of an accounting separation for terminal equipment, the Commission finds, pursuant to subsection 34(1) of the Act, that to forbear from regulating, as specified below, with respect to the sale, lease and maintenance of CT-O and CT-MD equipment, is consistent with Canadian telecommunications policy objectives. Further, pursuant to subsection 34(2) of the Act, the Commission finds that these services are subject to sufficient competition to protect the interest of users, so that forbearance is appropriate. Finally, with respect to subsection 34(3) of the Act, the Commission finds that to forbear is unlikely to impair unduly the continuation of a competitive market for these services.

Accordingly, pursuant to section 34 of the Act, the Commission hereby refrains, with respect to the sale, lease and maintenance of CT-O and CT-MD equipment, from the exercise of powers and the performance of duties with respect to sections 24, 25, 31, and subsections 27(1), (2), (4), (5), and (6) of the Act.

The Commission's decision to forbear does not apply to (1) terminal equipment supplied on a monopoly basis, more specifically to equipment required by tariff to be supplied by the telephone companies in conjunction with the provision of two-party, four-party or multi-party primary exchange services and (2) single-line residence and business inside wiring.

The independents are directed to file tariffs deleting reference to the sale, lease or maintenance of terminal equipment, as described above, upon approval by the Commission of a filing by each company or its association indicating that it has complied with the requirement to separate competitive terminal equipment assets, revenues and expenses from its rate base and shortfall determination.

The Commission notes that some independent telephone companies currently offer services which bundle competitive terminal equipment with monopoly services; for example, terminal display sets combined with Call Management Services. The Commission requires those companies to file tariff revisions which unbundle terminal equipment from such service offerings at the same time that terminal equipment tariffs are deleted.

IX EXTENDED AREA SERVICE

A. Extended Area Service Criteria

In Public Notice 95-15, the Commission noted that with respect to Extended Area Service (EAS), the current criteria for the establishment of EAS links in Bell's territory are:

(1) at least 60% of subscribers in one exchange must call customers in the other exchange at least once a month, for two months in a twelve-month period, referred to as community of interest (COI) criterion;

(2) the distance between the exchanges' switching centres must not exceed 40 miles or 64 kilometres; and

(3) a simple majority of subscribers experiencing a rate increase as a result of a new EAS link must agree to the implementation of EAS.

In Public Notice 95-15, the Commission proposed that the above approach also apply to the establishment of new EAS links within the territories of the other independents, or between their territories and that of a neighbouring telephone company.

The Commission notes that, for the Ontario independents, the Commission currently uses the Bell criteria, and as well has applied the one dollar voting rule introduced in Quebec.

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The Commission notes that most of the Ontario independents supported the use of the Bell criteria and the one dollar voting rule. Therefore, the Commission approves, for the Ontario independents, the Bell criteria modified to require a vote in the exchanges where the associated individual-line residential rate increase would be greater than one dollar per month.

With respect to the Quebec independents, the Commission notes that there are two EAS standards, depending on whether the independent telephone company is linked to a Bell exchange or to another independent's exchange. In the case of an EAS link to a Bell exchange, the Bell criteria apply, and in the case of an EAS link to Québec-Téléphone and Télébec, the criteria established in Québec-Téléphone - Development Plan for 1995-1999 and Revenue Requirement for 1995, Telecom Decision **CRTC 95-1**, 25 January 1995 and in Télébec Itée - Development Plan for 1995-1999 and Revenue Requirement for 1995, Telecom Decision **CRTC 94-26**, 29 November 1994 apply.

The small Quebec independents supported the use of the Bell criteria and the one dollar rule. However, given that the Commission has upheld the EAS criteria for Québec-Téléphone and Télébec in Decision 96-5, the Commission approves the continued use of the two criteria incorporating the one dollar voting rule.

In addition, the Commission directs all independents, to measure COI based on subscriber count as opposed to line count.

B. Method for Recovering the Cost of New Extended Area Service Links

Traditionally, telephone companies with local and toll operations recover the costs of EAS links by increasing local rates for those receiving the new EAS link through the application of higher rate group-based local tariffs. However, such rate increases only partially recover the costs of providing EAS, with the shortfall being paid for by the general body of subscribers from other sources of company revenue i.e., toll revenue. In the case of single exchange independents, the use of rate groups and toll cross-subsidies are not possible.

The Commission notes that, in his report, Mr. Grieve referred to one case in which the OTSC was not prepared to implement EAS from a Bell exchange to an independent exchange because of the associated cost to the independent telephone company in question. Similarly, in Bell Canada - Revised Criteria For Extended Area Service, Telecom Decision **CRTC 88-15**, 29 September 1988, the Commission stated that agreements between Bell and independent telephone companies in relation to EAS links should not burden Bell subscribers with costs that they have not caused.

Since the Commission commenced regulating the Ontario independents, there have been two requests for EAS links. In both cases, the Bell EAS criteria were met and the independent companies proposed local rate increases that would recover all costs associated with the new links. Bell was responsible for the costs associated with its network. This approach was adopted in order that the CAT not be increased and the subscribers benefitting from the new EAS link paid for it.

In Bell Canada - Neighbourhood Calling Plan, Telecom Decision **CRTC 92-22**, 9 December 1992, the Commission stated that while it would be prepared to consider departures from the EAS criteria for the creation of toll-free calling areas, it was of the view that the incremental costs of any such departures should be borne primarily by subscribers within the affected regions.

In Quebec, there have been cases where the EAS criteria have not been met and where the Commission approved the total cost of the new link, both Bell's cost and the independent's cost being paid only by the subscribers benefitting from the new link.

For the independents in Ontario and Quebec, the Commission will require that subscribers pay for the cost of EAS directly through higher local rates and that the CAT not be used for this purpose.

C. Resale of Extended Area Service

In Bell's territory, resale of EAS involving only "one-hop" is permitted without the payment of contribution.

Most independent companies were of the view that the resale of EAS to points outside the EAS territory should be prohibited to prevent contribution erosion. Sprint supported a ban on this type of resale until the Commission was sure that there would be no adverse effect on the smaller independents.

The Commission is of the view that to the extent possible, competition should be expanded. There is a concern, however, with the financial impact on the independent companies. EAS can be used to bypass contribution payable to the independents both by long distance

competitors who take advantage of EAS where the EAS link involves a Bell exchange and by local "one-hoppers". In Decision 92-12, the Commission did not allow long distance competitors to use Bell switches to originate traffic in the territories of parties who were not in the proceeding that led to that Decision. Competing long distance carriers were required to negotiate with the independents if they made use of Bell's EAS arrangements.

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Accordingly, the Commission approves the resale of EAS and directs that resellers of such services not be differentiated from resellers of long distance services and, therefore, that they be required to pay contribution. The payment of contribution on resold EAS recognizes the financial vulnerability of the independents. Resellers must register with the Commission and the relevant telephone company and provide, if requested to do so by the telephone company in question, traffic statistics to the telephone company for billing purposes and for calculating the CAT.

X QUALITY OF SERVICE

In Public Notice 95-15, the Commission noted that, in the proceeding initiated by Review of the Quality of Service Indicators, Telecom Public Notice **CRTC 94-50**, 21 October 1994, it would consider, among other things, the appropriate quality of service regulation for the largest of the independents, specifically, ED TEL Communications Inc., Northern, Québec-Téléphone, Télébec and Thunder Bay. For those independents with less than 25,000 NAS, the Commission proposed that issues pertaining to quality of service would be addressed via complaints lodged concerning a particular independent.

The Commission notes that no party opposed the Commission's proposal as set out in Public Notice 95-15. Therefore, the Commission approves the quality of service complaints procedure as outlined above for all the independents with less than 25,000 NAS. Specifically, the Commission endorses the independents' current practice of addressing quality of service concerns through complaints lodged with either the relevant telephone company or, in the case of the PUCs, with their respective municipal council. To ensure the protection of the subscribers' interest, the Commission further directs that, should a subscriber indicate dissatisfaction with the resolution of a complaint, the independent in question forward a copy of the written complaint and/or particulars of the verbal complaint to the Commission for resolution. The Commission notes that the complaint process is to be conducted with the relevant telephone company and not with the telephone company's association. However, this process would not preclude independents from contacting their association for advice.

With respect to the PUCs, while the Commission does not object to their proposal that complaints continue to be dealt with by the relevant municipal council, the Commission considers that a subscriber should also have the option of lodging a complaint/concern directly with the telephone department of the PUC. In either case, should the subscriber indicate dissatisfaction with the resolution of a complaint, the independent in question must forward a copy of the written complaint and/or the particulars of the verbal complaint to the Commission for resolution.

With respect to notifying subscribers of this procedure, the Commission maintains its view expressed in Review of the General Regulations of the Federally Regulated Terrestrial Telecommunications Common Carriers, Telecom Decision **CRTC 86-7**, 26 March 1986 (Decision 86-7), as amended by Telecom Order CRTC 86-593, 22 September 1986, that, in the interest of keeping customers fully informed, the introductory pages of directories should contain information regarding quality of service standards. The telephone companies are therefore directed to file within 60 days of the date of this Decision, for Commission approval, a text summarizing the requirements and procedures regarding the overall quality of service standards established pursuant to this Decision. The Commission further directs the independents to publish these procedures in the introductory section of the White Pages of the independents' next issue of directories and in the Bell directories in which customer listings for the independents are published. In the case of the PUCs, reference can be made to the municipal council complaint procedure as being an additional option available to customers.

The Commission notes that it does not require any of the independents that are party to this proceeding to file Quality of Service indicators, whereas the Stentor members are required to file quality of service indicators in addition to publishing the particulars of such standards.

XI TERMS OF SERVICE

A. General

In Public Notice 95-15, the Commission proposed that the independents be required to adopt the Terms of Service of either Bell or The Island Telephone Company Limited (Island Tel), allowing for some minor variations to respond to operating requirements and unique service characteristics. The Commission further stated that it is its policy that a telephone company's Terms of Service, or a summary thereof, be published in its telephone directory. The Commission noted, however, that certain independents do not publish their own telephone directories; rather, their subscribers are listed in the Bell directory for the area(s) nearest them. Therefore, the Commission proposed that should an independent that relies on Bell directories choose to adopt Island Tel's Terms of Service, subscribers be informed in Bell's

directory that Terms of Service similar to those set out in the directory apply and that copies of applicable Terms can be obtained from the independent in question.

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The Commission notes that, with the exception of a limited number of specific provisions, parties were generally not opposed to adopting Bell's Terms of Service. Accordingly, the Commission directs the independents to adopt Bell's Terms of Service, with the exceptions noted below for the independent in question.

With respect to ACTQ's request not to adopt Bell's Article 6 (Two-Party and Four-Party Service), while the Commission notes that ACTQ members have also undertaken upgrading programs, the Commission considers it appropriate to require ACTQ members to include a provision similar to Bell's Article 6 in their Terms of Service to address the possibility that some members may not have completed their upgrading program. Therefore, the Commission directs that ACTQ members adopt Bell's Articles 6.1 and 6.2.

With respect to Bell's Article 7.5 (Deposits and Alternatives) dealing with the interest rate payable on deposits, ACTQ requested that it maintain its current Article (which provides for an interest rate of 8% on deposits) because it is fair to subscribers and it is already programmed in the computer billing systems of its members. The Commission concurs with ACTQ's proposal as it minimizes the independent telephone companies' burden and maximizes subscriber returns. Should an economic situation arise such that an 8% return is no longer reasonable, the Commission may review this Article at such time. Similarly, the Commission concurs with ACTQ's request to retain its current version of Bell's Article 7.6. The Commission is of the view that the subscriber will be better off under the current conditions than under Bell's Article 7.6 as, while Bell's Article 7.6 requires that the interest accrued on deposits be shown on each customer's monthly account, ACTQ members currently pay out the interest monthly.

With respect to Bell's Article 7.6, the Commission agrees with OTA that requiring its members to adopt this Article may force them to make significant investment in their billing systems. In this regard, the Commission notes that in AGT, NBTel and Newfoundland Tel - Amendments to the General Regulations, Telecom Decision CRTC 95-6, 27 April 1995 (Decision 95-6), it approved for NewTel Communications Inc. (formerly Newfoundland Telephone Company Limited) and The New Brunswick Telephone Company, Limited, modifications to Article 7.6 based on similar arguments. As a result, the companies were directed to provide, on the monthly bills, the telephone number of a company representative to whom any inquiry regarding the deposit may be directed. The Commission directs that the same requirement apply to OTA member companies.

The Commission also finds ACTQ's request to add a clause to Bell's Article 8.3 (Restrictions on Use of Service) to limit the abuse of regional links to be reasonable. However, the Commission finds that the version of Article 8.3 proposed by ACTQ leaves a company too much discretion. Consequently, the Commission directs that the following be added as the second last sentence of this Article: "Telephone company may, to this end, where reasonable, limit the use of its services and request that a subscriber use private circuits under certain circumstances".

With respect to ACTQ's proposal to remove from their Terms of Service all references to the independents' responsibilities related to the provisioning of long distance services, the Commission notes that, currently, ACTQ members provide their customers with Bell toll service without informing Bell of the subscribers' credit records. Further, in cases of non-payment for toll services, Bell is neither able to identify the subscribers who do not pay their bills, nor is Bell able to terminate service as only ACTQ members can do so.

The Commission considers that if all references to the independents' responsibilities related to the provisioning of long distance services were removed from their Terms of Service, Bell would have to be provided with full control over the credit verification and monitoring process and, in cases of non-payment, over the denial of toll service. The Commission notes that, while ACTQ acknowledged that, in certain cases, Bell must be able to either refuse toll access or request that the independent do so, it did not, however, address other related issues. With respect to termination of toll services, Guèvremont proposed that Bell give it access to a databank such that it can do a background credit check of toll subscribers for Bell. However, the Commission finds that this approach would violate the privacy provisions of Bell's Terms of Service relating to the confidential nature of the information provided by the subscribers to their telephone company.

Given that ACTQ members currently perform credit checks and bill and collect toll charges, the Commission finds ACTQ's request to remove all references to responsibilities related to the provisioning of toll services from their Terms of Service to be unacceptable. The Commission notes that the references to toll in the proposed independents' Terms of Service (i.e., Bell's Terms of Service) are the most effective manner to impose the obligation to pay toll charges on subscribers. The Commission further notes that, if the ACTQ and Bell reach an agreement whereby ACTQ members no longer have responsibilities which substantially impact the conduct of Bell's toll business, they can file for tariff changes with the Commission.

In light of the above, the Commission denies ACTQ's proposal to modify the Terms of Service to remove all references to the independents' responsibilities related to the provisioning of toll services.

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B. Additional Provisions Applicable to All Independents

1. Implementation and Filing Requirements

The Commission remains of the view, expressed in Decision 86-7 and in Decision 95-6, that companies can be reasonably expected to implement new Terms of Service if provided with a six-month lead-time. However, given the limited resources available to some of the smaller independents, the Commission is of the view that the independents should have two months to file with the Commission their revised Terms of Service rather than the one-month timeframe envisaged in Decisions 86-7 and 95-6. The Commission notes that, although the companies are to implement their Terms of Service within six months, they are only required to update their directories at the next planned issue date.

2. Notice of New Terms of Service

The Commission directs the independents to advise their subscribers, through a billing insert, that new Terms of Service have been approved and that the Terms or a summary thereof will be published in the next telephone directory. The Commission further directs the companies to file the text of the billing insert, for Commission approval, within two months of the date of its Decision. Finally, the Commission directs the independents to notify their subscribers, in both official languages, that copies of the Terms of Service are available in either language upon request and that further information can be obtained from the company's business offices.

3. Inclusion of Terms of Service in the Directories of the Independents and Bell

The Commission considers that it would be in the subscribers' interest that the publication of information concerning the Terms of Service be made both mandatory and consistent across the territories of the independents.

The Commission agrees with OTA that, in cases where subscribers of the independents are listed in Bell directories, the inclusion of both sets of Terms of Service in the Bell directory would be needlessly duplicative and costly. The Commission further agrees with OTA's proposal that a notice should be included in the Bell directories advising customers that the Terms of Service of the independents are similar to those of Bell and that a copy of these Terms can be obtained at the independents' Business Offices. Therefore, the Commission directs Bell to publish such a notice to customers in the relevant directories.

In Decision 86-7, the Commission made a determination concerning the requirements applicable to Stentor members pertaining to the inclusion of the Terms of Service in their directories. The Commission considers that those requirements could also reasonably be applied to the independents. Accordingly, the Commission directs the independents and Bell, when its telephone directories include listings of independents' customers, to publish, in the introductory pages of the directories, either a summary or the full text of the Terms of Service, in both official languages where significant numbers of both language groups warrant such inclusion. Where a directory contains a summary or text in only one language, the Commission directs that a statement in the other official language be inserted stating that the Terms of Service are also available in the other official language and that the Terms of Service have equal force in both official languages. The Commission considers that such requirements are appropriate as they strike a balance between the need of subscribers to be fully informed in the language of their choice and the Commission's objective of minimizing the independents' burden.

XII CELLULAR ISSUES

A. Forbearance

The Commission notes that, currently, of the companies affected by this Decision, five independents are involved in the provisioning of cellular services: Sogetel which provides services through a separate affiliate, was recently granted forbearance, while Northern, Kenora, Thunder Bay and Cochrane provide regulated services through company divisions. All companies currently offering service through a company division requested forbearance.

In Regulation of Wireless Services, Telecom Decision **CRTC 94-15**, 12 August 1994 (Decision 94-15), the Commission decided to forbear from regulating the provision of cellular service or public cordless telephone service by Canadian carriers other than the telephone companies. However, this determination did not affect the status of the costing and marketing safeguards that were established in Cellular Radio - Adequacy of Structural Safeguards, Telecom Decision **CRTC 87-13**, 23 September 1987 (Decision 87-13) and Rogers Cantel Inc. v. Bell Canada - Marketing of Cellular Service, Telecom Decision **CRTC 92-13**, 29 June 1992 (Decision 92-13). The Commission further determined that, conditional upon the development and implementation of the appropriate safeguards, it would be prepared to

consider telephone company proposals to forbear with respect to the provisioning of wireless services.

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In this proceeding, the Commission notes that, in general, parties agreed with the findings of Decision 94-15 and with the requirement to apply the costing and marketing safeguards developed in Decisions 87-13 and 92-13. However, the PUCs and OTA (although only in respect of Cochrane) were opposed to the requirement to establish a separate cellular affiliate as a prerequisite to cellular forbearance. They argued that legal barriers prevent them from creating separate cellular affiliates and that, given that locally-elected officials represent the customers and that there is no possibility for financial gain for such officials, the PUCs should be given the latitude to regulate locally within Commission-established guidelines. Furthermore, although the PUCs proposed to implement marketing safeguards, they indicated that the nature of their ownership obviates the need for any additional safeguards, such as structural separation, cost separations or the filing of intercorporate transaction reports with the Commission.

The Commission notes that the PUCs are monopoly providers of local service. Further, the Commission agrees with Cantel that even though the PUCs are controlled by elected officials, that fact alone does not ensure that the public interest will be upheld if the Commission forbears from regulating cellular services. Rather, the Commission is of the view that safeguards are still needed, in the case of the PUCs or any other independent, to ensure that there is no cross-subsidization from monopoly telephone revenues and that no undue preference or advantage is conferred with respect to cellular operations. Moreover, the Commission does not consider that forbearance is appropriate in this case, even though there are legal barriers to the PUCs establishing a separate affiliate.

In light of the above, the Commission directs a PUC, or any other telephone company that wishes to offer cellular services through a division of a company which provides monopoly telephone services to either (1) as indicated in Decision 94-15, submit a proposal to the Commission, including appropriate costing and marketing safeguards, requesting forbearance from regulation; or (2) comply with the safeguards established in Decisions 87-13 and 92-13. The Commission further directs a telephone company offering cellular services through a structurally-separate affiliate and which seeks cellular forbearance under the terms and conditions established in Decision 94-15, to file such a request with the Commission.

B. Costing and Marketing Safeguards

In Decisions 87-13 and 92-13, the Commission established marketing and costing safeguards to be applied to the provisioning of cellular services by Stentor-member telephone companies. These safeguards included (1) mechanisms to ensure that no cross-subsidization from monopoly telephone to cellular revenues takes place; (2) a prohibition on joint marketing and advertising of telephone company and cellular services; (3) restrictions on customer referrals by the telephone company; and (4) a prohibition on access to telephone company monopoly and competitive customer information by a cellular affiliate or by a division.

The Commission notes that, at present, the independents that are involved in the cellular industry are either (1) marketing agents and/or dealers for cellular providers; or (2) cellular providers through company divisions; or (3) cellular providers through structurally-separate affiliates.

With respect to marketing agents or dealers for cellular providers, the Commission notes that, presently, no ACTQ member acts as either a marketing agent and/or dealer. In contrast, a number of OTA member companies and one PUC are currently acting as marketing agents and/or dealers for Bell Mobility Cellular (BMC) and are engaged in joint marketing and advertising of monopoly telephone company and cellular services, as well as in referring customers to only one cellular provider.

The Commission agrees, in part, with parties that, as these arrangements are not exclusive in nature, the cellular advertising and marketing opportunities available to BMC are also available to Cantel. The Commission is of the view that independents could engage in joint marketing and advertising without conferring any undue preference or advantage, under certain conditions. The Commission does, however, agree with Cantel that there is concern for undue preference or advantage given the independents' access to a monopoly local customer base and the unregulated nature of customer referrals.

In light of the above, the Commission is of the view that some of the safeguards established in Decisions 87-13 and 92-13 should be applied to independents who act as marketing agents and/or dealers for one or more cellular providers. Accordingly, the Commission directs such independents to apply the restriction on customer referrals such that independent agents and/or dealers refer potential customers to either all cellular providers (where applicable) or to none. The Commission further directs that the independent agents and/or dealers be prohibited from taking advantage of their access to monopoly and competitive customer information. However, the Commission is of the view that the prohibition on joint marketing and advertising of telephone company and cellular services developed in Decisions 87-13 and 92-13 need not be applied to independent agents and/or dealers, on the

condition that the independent be involved in an arm's-length relationship with the cellular provider and that the arrangement(s) be non-exclusive, available to third parties on the same terms and conditions and filed for approval with the Commission according to section 29 of the Act. If these conditions are not met, then the prohibition on joint marketing and advertising will apply.

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With respect to independents providing cellular services through a division of the company, the Commission notes that, currently, Cochrane, Kenora, Northern and Thunder Bay offer in-house cellular services. The Commission further notes that, although the PUCs proposed to implement the three marketing safeguards established in Decisions 87-13 and 92-13, they indicated that the nature of their ownership obviates the need for any additional safeguards, such as structural separation, cost separation or the filing of intercorporate transaction reports with the Commission.

The Commission, however, considers that the concerns expressed in Decisions 87-13 and 92-13 regarding the need for effective safeguards when telephone companies offer cellular services through a division of a company that provides monopoly services to ensure against cross-subsidization and undue preference remain valid. The Commission, therefore, agrees with Cantel that the independents which fall into this category should be subject to all of the safeguards established in Decisions 87-13 and 92-13 as they are monopoly providers of local services in their respective territories. Accordingly, the Commission directs that all safeguards established in Decisions 87-13 and 92-13 be applied to all independents, including the PUCs, who provide cellular services through a division of a company that also provides monopoly telephone services.

With respect to independents which provide service through separate cellular affiliates, the Commission notes that most parties supported the implementation of the safeguards established in Decisions 87-13 and 92-13 and that Sogetel has already implemented them. The Commission also notes ACTQ's proposal that the intercorporate transactions reports be submitted yearly, rather than quarterly, given the limited possibilities for cellular activity.

The Commission finds ACTQ's proposal to be reasonable. The Commission is of the view that this safeguard remains necessary to ensure that no cross-subsidization from monopoly telephone revenues takes place. The Commission also finds that marketing safeguards are necessary to ensure that no undue preference or advantage is conferred on a cellular provider.

In light of the above, the Commission directs all independents who provide cellular services through a separate affiliate to file yearly reports of intercorporate transactions between the affiliate and the telephone company. The Commission further directs all telephone companies subject to this Decision that are either currently offering or considering offering cellular services through a separate cellular affiliate, to comply with all other safeguards contained in Decisions 87-13 and 92-13, i.e., the prohibition on access by a cellular affiliate to telephone company monopoly and competitive customer information, the prohibition on joint marketing and advertising and the restrictions on customer referrals by telephone companies.

C. Access to Cellular Towers and Antennas

The Commission notes that, presently, some independents offer access to their cellular towers and antennas to interested parties on the same terms and conditions as those made available to the companies themselves or to an affiliate, while other independents do not make such terms available to the public. Further, none of these terms are currently filed with the Commission.

Presently, Stentor-member companies that own cellular towers and antennas are subject to two principal requirements. First, in AGT Limited - Revenue Requirement for 1992, Telecom Decision **CRTC 92-9**, 26 May 1992, and in Access to Telephone Company Support Structures, Telecom Decision **CRTC 95-13**, 22 June 1995, the Commission determined that when a telephone company provides access to cellular towers and antennas to an affiliate company, it must provide the same access to third parties. Second, in Notification of Network Changes, Terminal-to-Network Interface Disclosure Requirements and Procedures for the Negotiation and Filing of Service Arrangements, Telecom Letter Decision CRTC 94-11, 4 November 1994, the Commission determined that when a telephone company provides tower space to itself, and a party requires access to that space, the access provider is required to either file a non-discriminatory tariff arrangement or to indicate why such a service request is impractical.

The Commission notes the PUCs' request for regulatory forbearance and their proposal to develop compensatory rates, terms and conditions for the use of their facilities, should such requests occur. Further, the Commission agrees with Cantel's proposal that access to microwave towers owned by the independents should be governed by the same policy of non-discriminatory access which currently applies to Stentor members.

However, as the owners of these structures are monopoly suppliers in their respective territories such that there exists potential for access providers to confer an undue advantage

on some parties, the Commission will not forbear from regulating access to independent company support structures. The Commission is of the view that the requirements applicable to the Stentor members would ensure that access to independent cellular towers and antennas is not restricted and is available on a non-discriminatory basis.

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In light of the above, where an independent telephone company provides access to cellular towers and antennas to an affiliate company, the independent is directed to provide the same non-discriminatory tariffed access to third parties. Further, where a telephone company provides tower space to itself, and a party requires access to that space, the access provider is directed to file either a non-discriminatory tariff arrangement, or demonstrate why such a service request is impractical.

Allan J. Darling
 Secretary General

1. Amtelecom Inc.	11.625 -13.625
2. Coldwater Communications Inc.	11.625 - 13.625
3. Durham Telephones Ltd.	11.625 - 13.625
4. Hurontario Telephones Limited	12.00 - 14.00
5. The Lansdowne Rural Telephone Co. Ltd.	11.625 - 13.625
6. Manitoulin Tel Inc.	11.625 - 13.625
7. North Frontenac Telephone Corporation	11.625 - 13.625
8. North Norwich Telephones Limited	11.625 - 13.625
9. North Renfrew Telephone Co. Ltd.	11.125 - 13.125
10. Northern Telephone Limited	11.625 - 13.625
11. Otonabee Telephones Ltd.	12.00 - 14.00
12. People's Telephone Co. of Forest Ltd.	11.625 - 13.625
13. Roxborough Telephone Company Limited	11.625 - 13.625
14. South Bruce Rural Telephone Company Ltd.	12.00 - 14.00
15. Westport Telephone Co. Ltd.	11.125 - 13.125
16. Wightman Telephone Ltd.	12.00 - 14.00
17. Bruce Municipal Telephone System	10.375 - 12.375
18. Dryden Municipal Telephone System	10.375 - 12.375
19. Keewatin Municipal Telephone System	10.375 - 12.375
20. Kenora Municipal Telephone System	10.375 - 12.375
21. Thunder Bay Telephone	10.125 - 12.125
22. Brooke Telecom Co-operative Ltd.	10.325 - 12.325
23. Gosfield North Communications Co-Operatives Ltd	10.325 - 12.325
24. Hay Communications Co-Operative Limited	10.325 - 12.325
25. Huron Telecommunications Co-Operative Limited	10.325 - 12.325
26. Mornington Communications Co-operative Ltd.	10.325 - 12.325
27. Quadro Communications Co-operative Inc.	10.325 - 12.325
28. Tuckersmith Communications Co-operative Limited	10.325 - 12.325

Approved Return Ranges for the Ontario Independents

1. Amtelecom Inc.	11.625 -13.625
2. Coldwater Communications Inc.	11.625 - 13.625
3. Durham Telephones Ltd.	11.625 - 13.625

4. Hurontario Telephones Limited	12.00 - 14.00
5. The Lansdowne Rural Telephone Co. Ltd.	11.625 - 13.625
6. Manitoulin Tel Inc.	11.625 - 13.625
7. North Frontenac Telephone Corporation	11.625 - 13.625
8. North Norwich Telephones Limited	11.625 - 13.625
9. North Renfrew Telephone Co. Ltd.	11.125 - 13.125
10. Northern Telephone Limited	11.625 - 13.625
11. Otonabee Telephones Ltd.	12.00 - 14.00
12. People's Telephone Co. of Forest Ltd.	11.625 - 13.625
13. Roxborough Telephone Company Limited	11.625 - 13.625
14. South Bruce Rural Telephone Company Ltd.	12.00 - 14.00
15. Westport Telephone Co. Ltd.	11.125 - 13.125
16. Wightman Telephone Ltd.	12.00 - 14.00
17. Bruce Municipal Telephone System	10.375 - 12.375
18. Dryden Municipal Telephone System	10.375 - 12.375
19. Keewatin Municipal Telephone System	10.375 - 12.375
20. Kenora Municipal Telephone System	10.375 - 12.375
21. Thunder Bay Telephone	10.125 - 12.125
22. Brooke Telecom Co-operative Ltd.	10.325 - 12.325
23. Gosfield North Communications Co-Operatives Ltd	10.325 - 12.325
24. Hay Communications Co-Operative Limited	10.325 - 12.325
25. Huron Telecommunications Co-Operative Limited	10.325 - 12.325
26. Momington Communications Co-operative Ltd.	10.325 - 12.325
27. Quadro Communications Co-operative Inc.	10.325 - 12.325
28. Tuckersmith Communications Co-operative Limited	10.325 - 12.325

B+>Fourchettes de rendement approuvées pour les indépendantes de l'Ontario

1.	11,625 - 13,625
2.	11,625 - 13,625
3.	11,625 - 13,625
4.	12,00 - 14,00
5.	11,625 - 13,625
6.	11,625 - 13,625
7.	11,625 - 13,625
8.	11,625 - 13,625
9.	11,625 - 13,125
10.	11,625 - 13,625
11.	12,00 - 14,00
12.	11,625 - 13,625
13.	11,625 - 13,625
14.	12,00 - 14,00
15.	11,125 - 13,125
16.	12,00 - 14,00

17. 10,375 - 12,375
18. 10,375 - 12,375
19. 10,375 - 12,375
20. 10,375 - 12,375
21. 10,125 - 12,125
22. 10,325 - 12,325
23. 10,325 - 12,325
24. 10,325 - 12,325
25. 10,325 - 12,325
26. 10,325 - 12,325
27. 10,325 - 12,325
28. 10,325 - 12,325

Calcul de l'exigence de contribution

1. 11,625 - 13,625
2. 11,625 - 13,625
3. 11,625 - 13,625
4. 12,00 - 14,00
5. 11,625 - 13,625
6. 11,625 - 13,625
7. 11,625 - 13,625
8. 11,625 - 13,625
9. 11,625 - 13,125
10. 11,625 - 13,625
11. 12,00 - 14,00
12. 11,625 - 13,625
13. 11,625 - 13,625
14. 12,00 - 14,00
15. 11,125 - 13,125
16. 12,00 - 14,00
17. 10,375 - 12,375
18. 10,375 - 12,375
19. 10,375 - 12,375
20. 10,375 - 12,375
21. 10,125 - 12,125
22. 10,325 - 12,325
23. 10,325 - 12,325
24. 10,325 - 12,325
25. 10,325 - 12,325
26. 10,325 - 12,325
27. 10,325 - 12,325
28. 10,325 - 12,325

Calculation of the Contribution Requirement

The Commission directs the independents to calculate their contribution requirements, starting with their respective budget view by Broad Service Category (BSC) or Phase III equivalent, as follows:

1. Allocate the Common BSC expenses across all other BSCs in proportion to the operating expenses previously assigned to the other BSCs, and allocate the Common BSC investment in proportion to the ANIB previously assigned to the other BSCs;

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2016-0904
Page 000461

2. Remove all revenues, investment and expenses associated with cellular and terminal operations from the appropriate BSCs as directed in Part V, Section B of this Decision, and calculate the revised surplus/shortfall for the applicable BSCs;

3. Add the surplus/shortfall of the Access and Local BSCs;

4. If there is a surplus in the Network BSC, add it to the result of Step 3; and

5. If there is a surplus in the Other BSC, add it to the result of Step 4.

The Commission notes that the switching and aggregation charge will allow the small independents to recover their Toll BSC shortfall. In the case of ACTQ members, the Commission notes that individual companies will have to negotiate with Bell to replace the Contribution du Réseau and Recouvrement des Coûts Réseau components of their proposed CAT with a settlement process.

1995 and 1996 OTA and Northern CATs/ Les TSAE de l'OTA et de la Northern pour 1995 et 1996

1. OTA CAT

In Telecom Order **CRTC 96-131**, 19 February 1996 (Order 96-131), the Commission approved a final 1994 OTA CAT rate of \$0.1139 per minute (no equal access charge). In Order 96-131, the Commission also stated that the interim 1995 OTA CAT (of \$0.1166 per minute plus \$0.0007 per minute for equal access) was to be maintained at its existing level pending final approval at a later date.

Subsequent to the closing of the record of the proceeding initiated by Public Notice 95-15, OTA filed an application on 9 February 1996 for approval of a 1996 interim OTA CAT. Comments were received from the Amtelecom Group Inc. (Amtelecom Group) and the PUCs to which OTA filed a reply. The PUCs then filed additional comments.

Taking into account the positions of all parties, the Commission is of the view that the final 1995 OTA CAT should be determined in a manner consistent with the guidelines contemplated by OTA at the time of the interim filing for 1995, i.e., it should be finalized on the basis of 1995 actual Phase III results and in a manner similar to that used to finalize the 1994 OTA CAT. Also, the current interim rate for 1995 should remain interim until it can be finalized in late 1996, i.e., subsequent to OTA filing an application, with supporting documents including audited financial statements and actual Phase III results, to finalize the 1995 CAT.

Further, the Commission considers that the proposed change in methodology put forward by OTA with respect to the 1996 interim OTA CAT and the 1995 base used to determine that rate are not appropriate. In particular, the Commission is of the view that, under the circumstances, the Ontario independents need not take a 1% reduction in their respective rates of return simply because of the tax-paying status of the co-operatives that came into existence in 1995. The Commission notes that the 1995 interim OTA CAT rate does not reflect any amount for the income tax paying status of the co-operatives after that rate was approved. Thus, the Commission agrees with the Amtelecom Group that the final OTA CAT rate for 1995 could ultimately be higher than the current interim rate of \$0.1166 per minute once this factor is taken into consideration. Further, the Commission agrees with the Amtelecom Group that the same internal OTA CAT guidelines should be used for 1996, with the exception of the ANIB guideline; a reduction in that guideline to 5% appears reasonable, based on the evidence presented in this proceeding.

In light of the fact that the regulatory regime for the independents outlined in this Decision is to take effect on 1 January 1997, the Commission must finalize the 1996 OTA CAT in a timely manner. Accordingly, the Commission directs the OTA CAT participants to file a proposed 1996 OTA CAT, with supporting documentation, by 31 January 1997. This CAT filing is to be based on revised 1996 budget views (by BSC), including 10 months of actual data. Although the actual 1996 Phase III results will be available in the fall of 1997, the Commission intends to finalize the 1996 OTA CAT prior to, or at the same time as, the finalization of the individual CATs for 1997 (early in 1997). The OTA CAT participants also are to submit a comparison between the revised 1996 budget views (10 months of actuals) and the original budgeted views for 1996; this comparison is required for Commission assessment of the reasonableness of the proposed 1996 final OTA CAT.

Further, for administrative ease, the current interim rate (i.e., \$0.1166 per minute plus \$0.0007 per minute for equal access) will remain interim throughout 1996, pending a final determination of the 1996 OTA CAT rate in early 1997.

Regarding the true-up provision currently in the OTA CAT and whether it should be continued in the future, the Commission is of the view that extraordinary circumstances do exist in this case, and justify the continuation of the true-up mechanism during the transitional period leading up to the implementation of the regulatory regime established for the independents

in this Decision. By maintaining the status quo until 1 January 1997, the Commission considers that the majority of the transitional problems related to the development of the CAT will have been resolved. Maintaining the status quo during the period leading up to 1 January 1997 would also serve to minimize regulatory intervention. With the implementation of the regulatory framework as set out in this Decision in 1997, extraordinary circumstances no longer exist. Accordingly, the Commission concludes that no true-up will be allowed after the implementation of the new regulatory framework.

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2. Northern CAT

In Telecom Order **CRTC 95-465**, 13 April 1996 (Order 95-465), the Commission approved an interim 1995 Northern CAT of \$0.095 per minute (no equal access charge), effective 1 May 1995, and in Telecom Order **CRTC 95-1421**, 21 December 1995, approved an interim 1996 Northern CAT of \$0.0825 per minute, effective 1 January 1996 (based on Northern's filing dated 11 December 1995). The interim 1995 CAT reflected an eight-month recovery period only (it would have been \$0.088 per minute on an annualized basis). Also, this CAT did not include a true-up provision, but it included an incentive mechanism, agreed to by Northern and ONTC, whereby Northern would earn halfway between the bottom and the midpoint of its approved ROE range.

Subsequent to the closing of the record in this proceeding, on 11 December 1995, Northern requested that the Commission finalize its 1995 CAT. By letter dated 22 December 1995, ONT objected to Northern's request for final approval of the 1995 Northern CAT. ONT considered Northern's request premature, given that Order 95-465 stated that the settlement mechanism for Northern and the other independents would be finalized in the independents' proceeding.

Taking into account the positions of the parties noted above, the Commission directs that, in order to maintain consistency among all the Ontario independents, a true-up provision that parallels that of OTA be adopted for the 1995 and 1996 Northern CATs. This would resolve ONT's concern regarding contribution over-payments in 1995. Furthermore, the Commission is of the view that the current interim 1995 Northern CAT should remain in effect until the 1995 Northern CAT can be finalized on the basis of 1995 actual Phase III results, to be filed in October 1996. Regarding the final 1996 Northern CAT, the Commission directs Northern to file, by 31 January 1997, information identical to that being filed by OTA in the context of finalizing the OTA CAT for 1996.

1995 and 1996 CATs for the Quebec Independents

1. ACTQ CAT

In Telecom Order **CRTC 95-75**, 26 January 1995, the Commission granted interim approval to the 1994 Interim Access Tariff of \$0.1791 per minute proposed by the ACTQ (the interim ACTQ CAT). The proposed rate was based on the Commission and Line Haul Agreement between the ACTQ members and Bell.

With Telecom Order **CRTC 95-558**, 11 May 1995 (Order 95-558), the Commission established an interim competitive regime for all the independents in Quebec, effective 1 June 1995, thereby expanding the application of the interim ACTQ CAT. The Commission notes that this rate is still in effect.

On 26 April 1996, in order to expedite consideration of an ACTQ CAT for 1996, the Commission issued a letter asking the ACTQ to file, within 60 days of the date of the letter, Phase III results, toll revenue requirements and toll minutes on behalf of its members which are CAT participants.

By letters dated 17 July and 21 July 1996, the SATAT, on behalf of participating ACTQ CAT members, filed revised CATs for 1995 and 1996, respectively.

The Commission considers that these filings call into question the level of the interim ACTQ CAT currently in place.

The Commission considers that the 1995 ACTQ CATs should be finalized at this time and hereby grants final approval to the 1995 revised CATs filed by the SATAT, notably \$0.0954 per toll minute and \$1.9307 per 1/4 mile. The Commission is however of the view that parties should be given an opportunity to comment on the 1996 CATs before they are finalized. The Commission grants interim approval to the revised 1996 CATs filed by the SATAT, notably \$0.1014 per toll minute and \$2.2533 per 1/4 mile, from the date of this Decision. The SATAT is to provide forthwith a copy of their 21 July 1996 filing to any person which requests it. Interested persons have 30 days to comment, serving a copy on the SATAT. The SATAT has 10 days from the final date for comments to reply, serving a copy on those who filed comments.

The Commission notes that either ACTQ, on behalf of the SATAT members, or the SATAT members themselves should file proposed tariff pages forthwith.

2. Sogetel

Sogetel interconnects with Québec-Téléphone (approximately 73% of toll traffic) and with Bell (approximately 27% of toll traffic).

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In Order 95-558, the Commission ratified the revenue settlement rate of \$0.1791 per minute for toll traffic originating and/or terminating in the operating territories of the Quebec independents. However, Sogetel and Québec-Téléphone were in dispute with respect to the revenue settlement mechanism applicable in the territory of Sogetel. Sogetel maintained that the CAT of \$0.1791 per minute, as per Order 95-558, applied to the traffic with Québec-Téléphone. Québec-Téléphone maintained that the toll revenues should be settled based on the Commission and Line Haul Agreement established by la Régie.

Consequently, in Telecom Order **CRTC 96-181**, 26 February 1996, the Commission determined that, for 1995, Québec-Téléphone and Sogetel were to settle toll revenues based on the Commission and Line Haul Agreement. For 1996, the Commission determined that Order 95-558 applies.

The Commission is of the view that Sogetel should have only one CAT for all toll traffic within its territory. Therefore, the 1996 ACTQ CAT, given interim approval in this decision, will also apply to Sogetel's toll traffic with Québec-Téléphone and Bell.

3. St-Éphrem and St-Victor

Both St-Éphrem and St-Victor interconnect with Québec-Téléphone. The Commission is of the view that, as in the case of Sogetel, the Commission and Line Haul Agreement should be applicable for the toll revenue settlements of 1995.

The Commission further directs that the Commission and Line Haul Agreement remain in effect, throughout 1996 and, for 1997, on an interim basis, until company-specific CATs are approved for St-Éphrem and St-Victor.

4. Guèvremont

Guèvremont noted that, since 1985, it has been without an interconnection agreement with Bell, owing to the two companies' inability to agree on a revenue sharing formula.

In Order 95-558 issued 11 May 1995, the Commission gave interim approval to a CAT rate of \$0.1791 per minute to be used by all small Quebec independents, including Guèvremont. Since that time, Guèvremont has been billing and receiving payment from Bell on the basis of Order 95-558. Guèvremont suggested that the Commission should mandate the use of the CAT rate approved in Order 95-558.

As noted above, the SATAT recently filed revised contribution rates on behalf of participating ACTQ members for the years 1995 and 1996. As noted earlier, the Commission considers that the SATAT's filings call into question the level of the interim CAT currently in place for participating ACTQ members, and also for Guèvremont by virtue of Order 95-558. In particular, the Commission has concerns with respect to the appropriateness of leaving the interim ACTQ CAT in place for all of 1995 and 1996.

In light of the fact that Guèvremont is not a member of the SATAT, the Commission is prepared to leave the interim CAT in place at this time. Notwithstanding this, the Commission directs Guèvremont to show cause within 30 days of the date of this Decision as to why the company's 1995 and 1996 CATs should not be finalized at the levels proposed in the SATAT filings. Should the company choose to provide alternative rates, detailed supporting documentation should be provided. The company is to serve, at the same time, a copy of the filing on any person which requests it. The company is also to provide forthwith a copy to any person which requests it after the filing date. Interested persons have 30 days to comment, serving a copy on Guèvremont. Guèvremont has 10 days from the final date for comments to reply, serving a copy on those who filed comments.

Appendix V

Filing Requirements for New Regulatory Regime for Small Independents

Audited Financial Statements	Capital Expenditures (case by case)	
Updates to Accounting Manual or equivalent	Accounting Policies (major changes)	Accounting Manual or equivalent
Depreciation Studies (maximum five year intervals)		Establish Deferral Accounts (Ontario only)
Depreciation Life Characteristics (if changes)		Disposition Plans for Accumulated Account Balances in Deferral Accounts

		(Quebec only) Filed: 2016-03-21 EB-2016-0004 Page 000464
		Equal Access Roll-Out Plan
		PIC/CARE - Administration Procedures-Access Customer Handbook
		\$2.00 Increases-Billing Inserts-Tariff pages
Carrier Access Tariff (CAT)-Toll Minute Forecasts-Budget Views by BSC or equivalent-Contribution and Revenue Requirement Forecasts-Company-specific rates		Methodology forecluding cellular from Contribution and Revenue Requirement(if a Division)
Actual Phase III Results	Phase III initial review over 2 years (after two year period, by exception or on request)	
Phase III Manual Updates		
	Economic Studies in support of Tariffs (in certain circumstances)	De-tariff Terminal Equipment and Unbundle from Monopoly services
		Summary of Service Standards to be Published in Directories
		Revised Terms-Notice to Subscribers-Publish in Directory
		Forbearance Proposals
Intercorporate Transactions Report (if any)	Complaint Resolution Filings	
<p>PFF></p> <p>Exigences en matière de dépôt pour les petites indépendantes</p> <p>Nouveau régime de réglementation</p> <p>TABLE+>Accounting & Financial Matters</p> <p>Audited Financial Statements</p> <p>Capital Expenditures (case by case)</p> <p>Updates to Accounting Manual or equivalent Accounting Policies (major changes)</p> <p>Accounting Manual or equivalent Depreciation Studies (maximum five year intervals)</p> <p>Establish Deferral Accounts (Ontario only)</p> <p>Depreciation Life Characteristics (if changes)</p> <p>Disposition Plans for Accumulated Account Balances in Deferral Accounts (Quebec only)</p> <p>IX Competition</p> <p>Equal Access Roll-Out Plan</p> <p>PIC/CARE -Administration Procedures</p> <p>-Access Customer Handbook</p> <p>Rate Adjustments</p>		

\$2.00 Increases

-Billing Inserts-Tariff

pages**Toll Revenue**

Settlement

Mechanism

Carrier Access Tariff (CAT)

-Toll Minute Forecasts

-Budget Views by BSC or
equivalent

-Contribution and Revenue

Requirement Forecasts

-Company-specific rates Methodology for
excluding cellular from

Contribution and

Revenue Requirement

(if a Division)

Phase III

Actual Phase III Results

Phase III initial review

over 2 years (after

two year period, by

exception or on request) Phase III Manual Updates

Tariffs

Economic Studies in

support of Tariffs (in

certain circumstances)De-tariff Terminal

Equipment and Unbundle

from Monopoly services**Quality of**

Service

Summary of Service

Standards to be

Published in Directories**Terms of Service**

Revised Terms

-Notice to Subscribers

-Publish in Directory**Cellular**

Forbearance Proposals

Others

Intercorporate Transactions

Report (if any)Complaint Resolution

Filings

Exigences en matière de dépôt pour les petites indépendantes

Nouveau régime de réglementation

TAB 13

**Canada**

Canadian Radio-television and Telecommunications Commission

Home > Business and Licensing > Public Proceedings > Decisions, Notices and Orders
> ARCHIVED - Telecom Order CRTC 98-703

ARCHIVED - Telecom Order CRTC 98-703

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Telecom Order

Ottawa, 17 July 1998

Telecom Order CRTC 98-703

On 15 January 1998, The Corporation of the City of Thunder Bay - Telephone Division (Thunder Bay) filed an application for approval of tariff revisions reflecting changes to its primary exchange service.

File No.: Tariff Notice 54

1. Under Tariff Notice (TN) 54, Thunder Bay is proposing to eliminate mileage charges and locality rate areas in conjunction with a \$ 0.30 rate increase applied to all customers. Thunder Bay proposed to destandardize two and four party services and upgrade all current customers to individual line service by the end of 1998. Thunder Bay also proposed to expand its local free calling area to match Bell Canada's (Bell) Natural Calling Centre (NCC) for the Thunder Bay Area.

2. In support of its proposal, Thunder Bay submitted that mileage charges were a customer irritant and have deterred party line customers from upgrading to individual line service.

3. Thunder Bay proposed to recover the revenues foregone as a result of the elimination of mileage charges and locality rate areas through a \$ 0.30 rate increase applied across all network access service (NAS) lines.

4. Thunder Bay's rationale for requiring the upgrade of two and four-party service to individual line service is to improve service and decrease costs.

This document is available in alternative format upon request.

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Date modified: ???-??-??

Filed: 2016-03-21

EB-2016-0004

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This document is available in alternative format upon request.

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Date modified: ???-??-??

January 15, 1998

Mrs. Laura M. Talbot-Allan
 Secretary General
 Telecommunications
 Canadian Radio-television and
 Telecommunications Commission
 Ottawa, Ontario
 K1A 0N2

Dear Mrs. Talbot-Allan:

RE: TARIFF NOTICE 54 - Local Rate Rebalancing

In compliance with the requirements of the Telecommunications Act and section 29 of the CRTC Telecommunications Rules of Procedure, The Corporation of the City of Thunder Bay - Telephone Division (Thunder Bay Telephone) applies herewith for approval of the following tariff amendment(s).

<u>Tariff CRTC</u>	<u>Proposed Effective Date</u>	<u>Description</u>
25570	1998 04 01	Section TB50 / Page 1 / Revision 53
25570	1998 04 01	Section TB50 / Page 2 / Revision 24
25570	1998 04 01	Section TB50 / Page 4 / Revision 20
25570	1998 04 01	Section TB60 / Page 2 / Revision 7
25570	1998 04 01	Section TB60 / Page 5 / Revision 7
25570	1998 04 01	Section TB70 / Page 2 / Revision 2
25570	1998 04 01	Section TB70 / Page 6 / Revision 1
25570	1998 04 01	Section TB70 / Page 7 / Revision 3
25570	1998 04 01	Section TB70 / Page 9 / Revision 2
25570	1998 04 01	Section TB100 / Page 2 / Revision 6
25570	1998 04 01	Section TB100 / Page 3 / Revision 6
25570	1998 04 01	Section TB190 / Page 3 / Revision 3
25570	1998 04 01	Section TB210 / Page 2 / Revision 4
25570	1998 04 01	Section TB260 / Page 1 / Revision 1
25570	1998 04 01	Section TB260 / Page 2 / Revision 1
25570	1998 04 01	Section TB260 / Page 3 / Revision 4
25570	1998 04 01	Section TB260 / Page 4 / Revision 1
25570	1998 04 01	Section TB930 / Page 1 / Revision 3

Enclosed herewith are copies of the proposed new or revised tariff page(s) and a letter of explanation for the change(s) requested.

Yours very truly,

Lois Rieckenberg
 Regulatory Analyst

January 15, 1998

Mrs. Laura M. Talbot-Allan
Secretary General
Telecommunications
Canadian Radio-television and
Telecommunications Commission
Ottawa, Ontario
K1A 0N2

Dear Mrs. Talbot-Allan:

RE: TARIFF NOTICE 54 - Local Rate Rebalancing

Enclosed is The Corporation of the City of Thunder Bay - Telephone Division's (Thunder Bay Telephone or the Company) Tariff Notice 54 which proposes to continue to rebalance rates in conjunction with the provision of customer service improvements by upgrading all lines to individual-line service and matching the Natural Calling Centres (NCCs) as approved for Bell Canada customers. These proposed changes will affect all customers.

Telecom Order 96-1547 noted customer concerns about paying mileage charges and encouraged the independent telephone companies in Ontario who apply mileage charges to investigate ways to reduce or eliminate such charges. This tariff notice will address two major customer irritants: mileage and locality-rate area charges, and limited local calling. In addition, individual-line service will be established as the basic grade of service. The objectives of this tariff notice are the following:

- the Company proposes to eliminate mileage and locality-rate charges;
- the Company proposes to match Bell Canada's NCCs by extending local free calling from Thunder Bay territory to adjacent communities; and
- the Company proposes to upgrade all two and four-party services to individual-line services.

This application proposes to rebalance rates by increasing all residence and business basic access rates. The increased revenues from basic access rates will be used to eliminate mileage and locality-rate area charges and expand local free calling.

The Company feels these changes will simplify pricing and ensure the provisioning of a more consistent, high level of service throughout the Thunder Bay serving territory.

BUSINESS RATIONALE

1. Uniform Pricing

Thunder Bay Telephone has the goal of providing the same level of service to all its customers. The rate structure will be changed such that rates reflect the level of service provided. The proposed rate rebalancing charges the same price throughout the service area. The move to uniform rates is revenue neutral and will have no impact on the Company's net income.

2. Mileage Charges

Currently, those customers located outside the base-rate area who subscribe to individual-line or two-party service are charged extra-exchange distance and/or locality-rate area charges. Mileage charges are a customer irritant and a deterrent against four-party customers upgrading to individual-line service.

While Thunder Bay Telephone believes that the pricing of services should be based primarily on cost, the Company also believes that customers who are required to pay the same for their service as other customers must receive, to the extent possible, a relatively equivalent level of service.

As part of this proposal, the Company intends to eliminate mileage and locality-rate area charges. For 1997, on average there were 4,395 individual and two-party lines (or 5% of total network access lines) located outside the base-rate area and therefore subject to mileage and locality-rate area charges. With this filing, Thunder Bay Telephone proposes to eliminate mileage and locality-rate area charges and thus address the issue of fairness in our rate structure.

3. Upgrade to Individual-Line Service

The major reasons for upgrading two and four-party service to individual-line service are to improve service and decrease cost. Currently, over 1% of network access lines are multi-party, consisting of 140 two-party lines and 732 four-party lines. Due to technical constraints, some two and four-party customers are the only individuals on their respective lines, essentially receiving individual-line service without paying the higher individual-line tariffs. Thunder Bay Telephone will be able to provide all customers with individual-line service. For the majority of customers, facilities in exchanges are not a limiting factor to upgrading to individual-line. In many instances, customers have expressed interest in the upgrading of exchanges to provide individual-line but then refused private line service once the facilities are available.

As with most other forms of network access services, two and four-party service do not recover the cost of providing it. Multi-party customers cost more to provision than individual-line customers and the administrative and technical requirements associated with multi-party customers has made the service costly to maintain. Although it costs more to provide two and four-party service, a lesser amount is charged. Considering the goal of establishing individual-line as the basic grade of service and the cost issue, Thunder Bay Telephone believes it is no longer appropriate to provide multi-party service. With this filing, Thunder Bay Telephone is proposing to move these customers to individual lines and eliminate two and four-party service from our tariff.

Individual-line service will provide many benefits, including the ability to use modems, faxes, answering machines and calling features. Another major benefit for customers upgrading to individual-line service is that they will have the basic grade of service necessary to access the information highway without the additional cost of mileage or locality-rate area charges.

The individual-line upgrade initiative is included in the current capital construction program for 1998. As the Company rolls out individual-line service, two and four-party service will no longer be offered to new customers. Two and four-party customers will be upgraded to individual-line service as it becomes universally available. Subject to approval of this application, no additional two and four-party lines will be installed after 1 April 1998, except for these areas with the following release dates: Lappe, O'Connor, Nolalu, and Conmee (June); Surprise Lake, One Island Lake, and Pearson (September); Hymers (October); and South Gilles (December).

The Company is prepared to commit to the conversion of all two and four-party lines to individual-line service beginning approval of this application, to be completed by 31 December 1998. Under the current tariff structure, customers will not pay a service charge for upgrading to individual-line service. At a minimum, the Company will commit to providing each residence customer with at least one individual-line service. New residential second-line services will be added subject to the availability of facilities. Cross impacts from changes in demand for second-line service have not been included in this proposal.

4. Local Free Calling

In order to meet customer needs, Thunder Bay Telephone established Extended Area Service (EAS) to provide free calling throughout its service area. In response to Telecom Decision CRTC 97-18 which approved Bell Canada's proposal to establish expanded local calling based on Natural Calling Centres (NCCs), Thunder Bay Telephone proposes to match Bell Canada's local calling area for its customers.

Thunder Bay Telephone believes there is an opportunity to restructure local free calling. Expanding local calling based on Bell Canada's NCCs will harmonize local calling with Bell Canada's customers and eliminate the one-way toll-free calling issue. The Company's proposal extends the local free calling area territory to include all of the communities where one-way toll-free calling currently exists. Attachment 1 shows a diagram of the proposed local free calling area. Providing local calling in adjacent exchanges will also increase the value of local telephone service.

COSTS/BENEFITS

The benefits from this proposal are the following:

- the removal of customer irritants (namely, mileage, locality-rate area charges and one-way toll-free calling);
- the provision of the same level of service to all customers (namely, individual-line service as the basic grade of service); and
- the simplification of rates.

One rate will make it easier for customers to understand and for employees to administer. A simplified rate structure will reduce errors in customer accounts, reduce the time it takes to explain basic service to customers and decrease complaints to customer service about mileage, locality-rate area charges and one-way toll-free calling.

The majority of facilities are in place to provide individual-line service. All network and facilities costs for individual-line service have been built into the Company's business plan for 1998. Attachment 2 provides the Company's total revenue impact.

OPTIONAL MONOPOLY FEATURES

The Company anticipates increased revenue from Call Management Services, Custom Calling Features, and Touch-Tone and lower set rental revenues from those two and four-party customers that upgrade to individual-line. See Attachment 3 for estimated optional monopoly feature revenue impacts.

PROPOSED RATES

The proposal for rate rebalancing is based on the ease of administration of rates and the establishment of individual-line service as the basic grade of service. By averaging lost revenue across the total customer base, the proposed rate changes mitigate, to the extent possible, the impact on customers in terms of both dollar and percentage increases. Until customers have been upgraded to individual-line service, they will continue to pay the proposed two and four-party rates. Attachment 4 provides the current and proposed rates.

CUSTOMER AND REVENUE IMPACTS

With the proposed changes, how residence and business customers will be affected depends on whether or not they are located in the base-rate area and their current level of service. For some customers, their total monthly bill will increase, for others their bill will decrease. The largest increase will be for four-party customers upgraded to individual-line. The largest decrease will be for individual-line customers who currently pay mileage and locality-rate area charges. Attachment 5 provides the rate changes for each locality-rate area. Most customers will be affected by a \$0.30 increase to their basic access rate. Excluding mileage charges and toll from NCCs, for Business and Residence customers, 95% (80,501 customers) will see an increase of \$0.30; 1% (927 customers) will see an increase between \$0.55 and \$8.80; and 4% (3,122 customers) will see a decrease between \$0.05 and \$7.20 to their monthly network access line rate.

CUSTOMER NOTIFICATION

Customers will be notified by a bill insert explaining how the proposed changes in this filing will affect them. In addition, Thunder Bay Telephone will place advertisements and public service announcements in the local newspapers.

SUMMARY

Thunder Bay Telephone hereby requests approval for the following proposed revisions:

1. eliminate mileage and locality-rate area charges in conjunction with a rate increase of \$0.30 per network access line;
2. eliminate one-way toll-free calling by expanding local calling to the same communities approved for Bell Canada's customers; and
3. discontinue two and four-party service by 31 December 1998.

The Company submits this proposal which will provide a universal standard of high quality service to all its customers.

CONFIDENTIALITY

In accordance with Section 39 of the Telecommunications Act, the Company claims confidentiality for the cost, revenue and customer information contained in Attachments 2 and 3. The attachments contain specific marketing and revenue information which, if made public, will cause Thunder Bay Telephone undue harm insofar as it would provide competitors with information not generally available. An abridged version of Attachments 2 and 3 have been provided for the public record.

APPROVAL AND EFFECTIVE DATES

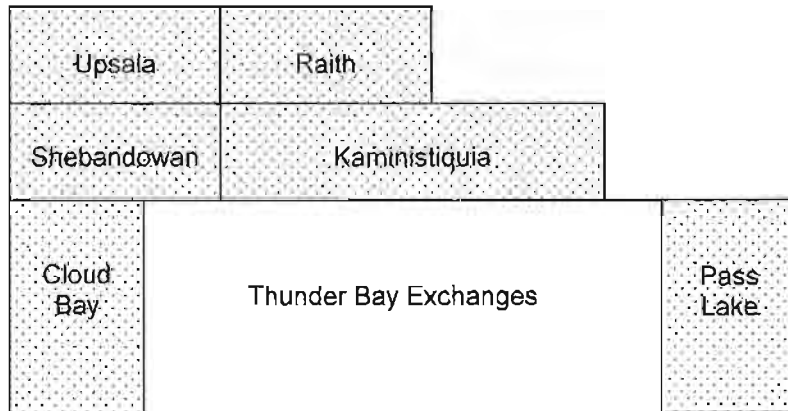
These changes are to take effect beginning 1 April 1998. In order to facilitate system and billing changes and customer notification, Thunder Bay Telephone requests approval of this application 30 days in advance of the requested effective date, 1 March 1998.

Should you have any questions regarding this application, please do not hesitate to contact me by telephone at (807) 684-3519, or by fax at (807) 346-0909.

Yours very truly,

Lois Rieckenberg
Regulatory Analyst

Proposed Local Free Calling Area



Toll-free calling to Bell Canada adjacent exchanges proposed by Thunder Bay Telephone.

Revenue Impacts

Annual Revenue Impacts

1) Two and four-party paying individual-line rate	\$15,792
2) Optional monopoly features*	\$22,096
3) Elimination of mileage and locality-rate area charges	<u>(\$316,776)</u>
Total	(\$278,888)

* see Attachment 3 for details

Optional Monopoly Features

	Individual-Line	Two-Party	Four-Party
RESIDENCE			
Touch-Tone Penetration	74%	23%	29%
Average Monthly Set Revenue	\$1.94	\$2.26	\$2.18
Average Monthly Calling Features Revenue	\$1.41	\$0.00	\$0.00
BUSINESS			
Touch-Tone Penetration	75%	43%	21%
Average Monthly Set Revenue	\$2.66	\$2.51	\$2.61
Average Monthly Calling Features Revenue	\$2.51	\$0.00	\$0.00

Optional Monopoly Feature Cross-Impact

	<u>Annual Revenue Gain (Loss):</u>
Touch-Tone	\$8,268
Set Rentals	(2,328)
Calling Features	<u>16,164</u>
Total	\$22,096

Assumes take rates for two and four-party in locality-rate areas will be the same as current take rates for individual-line customers in locality-rate areas.

Illustrative Rates

Description	Current Basic Exchange	Proposed Basic Exchange	Rate Change
Residence - Individual Line	\$10.75	\$11.05	\$0.30
Residence - Two Party Line	\$9.50	\$9.50*	-
Residence - Four Party Line	\$9.50	\$9.50*	-
Business - Individual Line	\$24.00	\$24.30	\$0.30
Business - Two Party Line	\$17.50	\$17.50*	-
Business - Four Party Line	\$15.50	\$15.50*	-
Trunk - Standard Business Line	\$35.00	\$35.30	\$0.30
Trunk - Hotel/Motel Guest	\$15.50	\$15.80	\$0.30
Trunk - Hospital Patient Use	\$15.50	\$15.80	\$0.30
Tie Trunk Terminal - Tandem	\$23.05	\$23.35	\$0.30
Basic Centrex III - per local	\$28.25	\$28.55	\$0.30
Centrex III Trunk - each	\$41.50	\$41.80	\$0.30
Voicecom Access Line	\$137.75	\$138.05	\$0.30

* Two and four-party rates apply until service is upgraded to individual-line.

Illustrative rates do not include Touch-Tone.

Revenue Impacts

Annual Revenue Impacts

1) Two and four-party paying individual-line rate	\$15,792
2) Optional monopoly features*	\$22,096
3) Elimination of mileage and locality-rate area charges	<u>(\$316,776)</u>
Total	(\$278,888)

* see Attachment 3 for details

Optional Monopoly Features

	Individual-Line	Two-Party	Four-Party
RESIDENCE			
Touch-Tone Penetration	74%	23%	29%
Average Monthly Set Revenue	\$1.94	\$2.26	\$2.18
Average Monthly Calling Features Revenue	\$1.41	\$0.00	\$0.00
BUSINESS			
Touch-Tone Penetration	75%	43%	21%
Average Monthly Set Revenue	\$2.66	\$2.51	\$2.61
Average Monthly Calling Features Revenue	\$2.51	\$0.00	\$0.00

Optional Monopoly Feature Cross-Impact

	<u>Monthly Revenue Gain (Loss)</u>	<u>Annual Revenue Gain (Loss):</u>
Touch-Tone	\$689	\$8,268
Set Rentals	(194)	(2,328)
Calling Features	<u>1,347</u>	<u>16,164</u>
Total	\$1,841	\$22,096

Assumes take rates for two and four-party in locality-rate areas will be the same as current take rates for individual-line customers in locality-rate areas.

Assumes features are available in all exchanges outside the base-rate area.

CRTC, Laura M. Talbot-Allan
Thunder Bay Telephone Tariff Notice 54
January 15, 1998

Attachment 7
Filed 2016-03-21
EB-2016-0004
Page 000482

NOTICE TO CUSTOMERS

On January 15, 1998 Thunder Bay Telephone applied to the Canadian Radio-television and Telecommunications Commission (CRTC) to restructure local service as follows:

(1) eliminate mileage and locality-rate area charges currently applicable to individual-line and two-party customers located outside the base-rate area boundary;

(2) convert all two and four-party lines to individual-line service by the end of December 1998; and

(3) match Bell Canada's local-free calling area by extending toll-free calling from Thunder Bay to these exchanges: Cloud Bay, Kaministiquia, Pass Lake, Raith, Shebandowan, and Upsala.

Pursuant to approval of Tariff Notice 54, Thunder Bay Telephone proposes that monthly rates for local access service (excluding two and four-party lines) be increased by \$0.30. The increase is required to offset lost revenue from the proposed changes and will have no impact on Thunder Bay Telephone's net income.

Before finalizing its decision with respect to its view on the implementation of these proposed changes, the Canadian Radio-television and Telecommunications Commission will entertain comments from customers on this matter.

To this end, written comments may be submitted to the Commission on or before March 31, 1998 and addressed to:

**Mrs. Laura Talbot-Allan
Secretary General
Canadian Radio-television
and Telecommunications Commission
Ottawa, Ontario
K1A 0N2
fax: (819)953-0795**

Submissions should clearly identify that the comments are made concerning Proposed Tariff Notice 54 - Local Rate Rebalancing for Thunder Bay Telephone.

Copies of comments must be directed to:

Mrs. Lois Rieckenberg, Regulatory Analyst,
The Corporation of the City of Thunder Bay,
Telephone Department
1046 Lithium Drive
Thunder Bay, Ontario
P7B 6G3

Thunder Bay Telephone must reply to comments within 10 days from the end of the submission period and forward a copy to the Commission.

PROPOSED RATE CHANGES -LOCAL ACCESS SERVICE

Monthly Rates

<u>Service Description</u>	<u>Current</u>	<u>Proposed</u>
Residence-Individual Line	\$ 10.75	\$ 11.05
Residence-Two Party Line*	\$ 9.50	\$ 9.50
Residence-Four Party Line*	\$ 9.50	\$ 9.50
Business-Individual Line	\$ 24.00	\$ 24.30
Business-Two Party Line*	\$ 17.50	\$ 17.50
Business-Four Party Line*	\$ 15.50	\$ 15.50
Trunk-Standard Business Line	\$ 35.00	\$ 35.30
Trunk-Hotel/Motel Guest	\$ 15.50	\$ 15.80
Trunk-Hospital Patient Use	\$ 15.50	\$ 15.80
Tie Trunk Terminal-Tandem	\$ 23.05	\$ 23.35
Basic Centrex III-per local	\$ 28.25	\$ 28.55
Centrex III Trunk-each	\$ 41.50	\$ 41.80
Voicecom Access Line	\$ 137.75	\$ 138.05

* Two and four-party service will not be provided after December 31, 1998.

If you do not wish to participate in this matter, the Commission may proceed in your absence.

For further information, please contact Lois Rieckenberg at 684-3519.



NOTICE TO CUSTOMERS

Thunder Bay Telephone is proposing to:

- 1) eliminate mileage and locality-rate area charges;
- 2) convert all two and four-party lines to individual-line service by the end of December, 1998; and
- 3) extend toll free calling from Thunder Bay to Cloud Bay, Kaministiquia, Pass Lake, Raith, Shebandowan, and Upsala.

In order to offset lost revenue from these changes, Thunder Bay Telephone proposes to increase local access service (excluding two and four-party lines) by \$0.30.

Sample of Proposed Rate Changes:

	<u>Current</u>	<u>Proposed</u>
Residence-Individual Line	\$10.75	\$11.05
Business-Individual Line	\$24.00	\$24.30
Trunk-Standard Business Line	\$35.00	\$35.30
Basic Centrex III-per local	\$28.25	\$28.55

Rates do not include Touch-Tone or Relay service.
Current rate does not include mileage and locality-rate area charges.

Written comments may be submitted to the CRTC on or before March 31, 1998. For further information, please contact Lois Rieckenberg at 684-3519.

Script for Customer Comments

One Price:

- rates will reflect the level of service provided
- charge the same price throughout the service area

\$0.30 rate change:

- will have no impact on our profit (neutral);
- will simplify rates (easier for employees and customers to understand)
- averages lost revenue across the total customer base
- our rates are still affordable, esp. in comparison to Bell's
- the price you pay for local service is only a fraction of what it costs to provide the service.
- local access service prices have been kept artificially low through subsidies from other services, primarily long distance services

Elimination of Mileage/Locality:

- mileage charges are a customer irritant
- mileage deters customers from upgrading to individual-line service
- 2/4 party lines cost more to maintain than single-party lines

Single Line Service:

- provide the same level of service to all its customers
- customers have shown interest in single line but refused once the facilities are available.

Benefits:

- ability to use modems, faxes, answering machines, calling features.
- access the info. highway (internet) without paying mileage/locality

- EAS:**
- extends toll free calling to adjacent communities
 - match Bell's toll free calling
 - will increase the value of local telephone service.

TAB 14



March 2, 2016

Northwestern Ontario Municipal Association
P.O. Box 10308
Thunder Bay, ON
P7B 6T8

Dear Mr. Angus:

RE: Expansion of Natural Gas Service

At a regular Committee of the Whole meeting held on March 1, 2016, members of Council in attendance supported a resolution regarding the expansion of natural gas service.

A formal resolution will be introduced at the March 15, 2016 meeting at which time can be forwarded to officially demonstrate the City of Kenora's support to NOMA on this matter.

Thank you for your continued work to represent matters important to northern Ontario municipalities.

Sincerely,

David S. Canfield
Mayor



The Corporation of the Town of Atikokan
Box 1330
Atikokan, Ontario P0T 1C0
tel (807) 597-1234

Filed: 2016-03-21
EB-2016-0004
Page 000489

Memo

To: admin@noma.on.ca
From: Dennis Brown, Mayor
Cc: Atikokan Town Council, Angela Sharbot CAO/Clerk
Date: March 1, 2016
Re: Support regarding the Expansion of Natural Gas Service in NWO

Atikokan Town Council is certainly supportive of the expansion of Natural Gas Service to the 15 rural and remote municipalities in Northwestern Ontario.

Our next regular meeting of Council is scheduled for March 14, 2016 and during that meeting we will bring forward an official resolution of support for expanded natural gas service in Northwestern Ontario.

Thanks for working on advancing this very worthwhile initiative to enhance the quality of life and economic benefits for Northwestern Ontario.

THE CORPORATION OF THE TOWN OF ATIKOKAN

COUNCIL RESOLUTION

Date: 14 Mar 2016

Moved by: Mary Makarenko

Seconded by: [Signature]

WHEREAS there are 14 rural and remote municipalities in Northwestern Ontario and a number of First Nation communities who do not have direct access to piped natural gas; and
 WHEREAS the residents and businesses in those communities without natural gas service must pay significantly more to heat their buildings and homes than communities with natural gas service; and
 WHEREAS we believe there is a public interest and benefit in extending natural gas services to rural and remote communities; and
 WHEREAS we often hear from the residents and businesses expressing their interest in having access to natural gas and the limitations and barriers they face in not having access to natural gas causes; and
 WHEREAS current economic tests and ratemaking mechanisms associated with new connections to the existing natural gas distribution system do not encourage utilities to expand in Northwestern Ontario; and
 WHEREAS currently natural gas expansion in Northwest Ontario requires the new customers to pay. In contrast the vast majority of the existing system was paid for by the rate payers as a whole; and
 WHEREAS the Ontario Energy Board has initiated a hearing on its own motion to consider what mechanisms may be used to recover the costs of expanding natural gas service to Ontario communities that do not currently have access to natural gas; and
 WHEREAS NOMA, NOACC and CVNW (the Coalition) have requested intervenor status on behalf of their member ratepayers (current and future) in Northwestern Ontario; and
 WHEREAS the position of the Coalition is that the cost of expanding natural gas service to communities without it should be shared by all gas rate payers in the Province of Ontario and the OEB implement new ratemaking mechanisms including changes to current economic tests to expand natural gas distribution on such basis.
 NOW THEREFORE BE IT RESOLVED THAT The Corporation of the Town of Atikokan advises the Ontario Energy Board that it supports the position adopted by NOMA, NOACC and CVNW that the expansion of the natural gas distribution system should be paid for by all current and future gas rate payers and the OEB implement new ratemaking mechanisms including changes to current economic tests to expand natural gas distribution on such basis.

RECORDED VOTE	COUNCIL MEMBER			
	YEA	NAY	CARRIED	DEFEATED

RESOLUTION NO 75/16 CARRIED BY [Signature]



The Corporation of the
Township of Ignace

Filed: 2016-03-21

EB-2016-0004

Page 000491

34 Highway 17 West P.O. Box 248 Ignace, ON P0T 1T0

March 2, 2016

Ontario Energy Board

M04.2016

Via email only

Dear Board Members,

Re: Expansion of Natural Gas Service in Northwestern Ontario

On behalf of Council I write to express our support for the position adopted by NOMA, NOMA, NOACC and CVNW that the expansion of the natural gas distribution system should be paid for by all current and future gas rate payers and the OEB implement new ratemaking mechanisms including changes to current economic tests to expand natural gas distribution on such basis.

Yours truly,

Lee Kennard
Mayor

cc NOMA



The Corporation of the Township of Alberton

Filed: 2016-03-21
EB-2016-0004
Page 000492

Corner of Hwy 11/71 & Hwy 611 South - Mailing Address: RR #1 – B2, Fort Frances, Ontario, P9A 3M2

Telephone: 807-274-6053
Fax: 807-274-8449
e-mail: alberton@jam21.net
website: www.alberton.ca

March 3, 2016

Northwestern Ontario Municipal Association
P. O. Box 10308
Thunder Bay, Ontario
P7B 6T8

ATTENTION: MR. DAVE CANFIELD, President

Dear Sir:

**Re: Ontario Energy Board Consultation on Cost Recovery for
Expansion of Natural Gas Services – EB-2016-0004**

Whereas:

1. There are 14 rural and remote municipalities in Northwestern Ontario and a number of First Nation communities which do not have direct access to piped natural gas;
2. There are communities such as Alberton where natural gas service is provided to only a portion of the municipality;
3. The residents and businesses in those communities without natural gas service must pay significantly more to heat their buildings and homes than communities with natural gas service;
4. There is a public interest and benefit in extending natural gas services to rural and remote communities;
5. We often hear from the residents and businesses expressing their interest in having access to natural gas, and the limitations and barriers they face in not having access to natural gas causes;
6. Current economic tests and ratemaking mechanisms associated with new connections to the existing natural gas distribution system do not encourage utilities to expand in Northwestern Ontario;
7. Currently, natural gas expansion in Northwest Ontario requires the new customers to pay. In contrast the vast majority of the existing system was paid for by the rate payers as a whole;
8. The Ontario Energy Board has initiated a hearing on its own motion to consider what mechanisms may be used to recover the costs of expanding natural gas service to Ontario communities that do not currently have access to natural gas;
9. NOMA, NOACC and CVNW (the Coalition) have requested intervenor status on behalf of their member ratepayers (current and future) in Northwestern Ontario;

10. The position of the Coalition is that the cost of expanding natural gas service to communities without it should be shared by all gas rate payers in the Province of Ontario and the OEB implement new ratemaking mechanisms including changes to current economic tests to expand natural gas distribution on such basis,

on behalf of Council for the Township of Alberton, I confirm to the Ontario Energy Board that Council supports the position adopted by NOMA, NOACC and CVNW that the expansion of the natural gas distribution system should be paid for by all current and future gas rate payers and the OEB implement new ratemaking mechanisms including changes to current economic tests to expand natural gas distribution on such basis.

Yours truly,

A handwritten signature in black ink, appearing to read "Michael Hammond". The signature is written in a cursive, flowing style with a large initial "M".

Michael Hammond
Reeve

CORPORATION OF THE TOWNSHIP OF CHAPPLE

Filed: 2016-03-21
EB-2016-0004
Page 000494

P.O. Box 4

BARWICK, ONTARIO POW 1A0
Phone 807-487-2354 Fax 807-487-2406

OFFICE OF THE CLERK-TREASURER
e-mail: chapple@lbaytel.net

March 2, 2016

Northwestern Ontario
Municipal Association
P.O. Box 10308
Thunder Bay, Ontario
P7B 6T8

RE: **Ontario Energy Board Consultation on Cost Recovery for Expansion of Natural Gas Services – EB-2016-0004**

Dear Board Members;

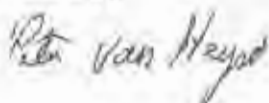
The Township of Chapple is a rural municipality in Northwestern Ontario that does not have direct access to piped natural gas for the majority of our residents. These residents must pay significantly more to heat their homes and buildings in comparison to other residents with access to a natural gas service.

As a representative for the Township of Chapple, I hear the concerns being expressed by our residents and businesses at not having access to natural gas and the hardship it causes.

The Township of Chapple strongly supports NOMA, NOACC and CVNW in their endeavours to expand the natural gas distribution system in Northwestern Ontario and are in agreement that this expansion should be paid for by all current and future gas rate payers and the OEB should implement new ratemaking mechanisms including changes to current economic tests to expand natural gas distribution on such a basis.

Thank you for your continued efforts on behalf of Northwestern Ontario.

Sincerely,



Peter Van Heyst, Reeve
Township of Chapple



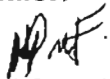
**The Corporation of the
Township of Schreiber**

Resolution # 59-10

Date: March 3, 2016

Moved by Councillor: 

Seconded by Councillor: 



WHEREAS there are 21 rural and remote municipalities in Northwestern Ontario and a number of First Nation communities who do not have direct access to piped natural gas; and

WHEREAS the residents and businesses in those communities without natural gas service must pay significantly more to heat their buildings and homes than communities with natural gas service; and

WHEREAS we believe there is a public interest and benefit in extending natural gas services to rural and remote communities; and

WHEREAS we often hear from the residents and businesses expressing their interest in having access to natural gas and the limitations and barriers they face in not having access to natural gas causes; and

WHEREAS current economic tests and ratemaking mechanisms associated with new connections to the existing natural gas distribution system do not encourage utilities to expand in Northwestern Ontario; and

WHEREAS currently natural gas expansion in Northwest Ontario requires the new customers to pay; in contrast the vast majority of the existing system was paid for by the rate payers as a whole; and

WHEREAS the Ontario Energy Board has initiated a hearing on its own motion to consider what mechanisms may be used to recover the costs of expanding natural gas service to Ontario communities that do not currently have access to natural gas; and

WHEREAS NOMA, NOACC and CVNW (the Coalition) have requested intervenor status on behalf of their member ratepayers (current and future) in Northwestern Ontario; and

WHEREAS the position of the Coalition is that the cost of expanding natural gas service to communities without it should be shared by all gas rate payers in the Province of Ontario and the OEB implement new ratemaking mechanisms including changes to current economic tests to expand natural gas distribution on such basis;

THEREFORE, be it resolved that the Township of Schreiber advises the Ontario Energy Board that it supports the position adopted by NOMA, NOACC and CVNW that the expansion of the natural gas distribution system should be paid for by all current and future gas rate payers and the OEB implement new ratemaking mechanisms including changes to current economic tests to expand natural gas distribution on such basis.

Pecuniary Interest	Recorded Vote	Council Member	Nay	Yea
		Councillor D Hamilton		
		Councillor G Krause		
		Councillor D Mauro		
		Councillor D Sales		
		Mayor M Figliomeni		

CARRIED



DEFEATED

Mayor:

A large, stylized handwritten signature is written over a horizontal line.

Clerk:

A horizontal line is drawn below the signature.



Filed: 2016-03-21
The Corporation of the Town of Marathon
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Marathon, Ontario P0T 2E0
mayor@marathon.ca
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Fax: (807) 229-1999
www.marathon.ca

OFFICE OF THE MAYOR

March 2, 2016

Mr. David Canfield
President
Northwestern Ontario Municipal Association
P.O. Box 10308
Thunder Bay, ON
P7B 6T8

VIA EMAIL

Dear Mr. Canfield:

Access to natural gas can stimulate economic growth by attracting and fostering industrial development, making commercial transportation cleaner and more affordable, helping our agricultural producers thrive and providing consumers with a lower cost energy choice.

Many parts of Ontario have benefited tremendously from historically low and relatively stable gas commodity prices. While there has been significant expansion of supply infrastructure in Southern Ontario, numerous towns and industrial facilities in rural and Northern Ontario still have no capacity to receive natural gas due to the high capital cost to build pipelines to these communities. So they continue to rely on propane, wood, fuel oil, and electricity for heating, creating significant intra-provincial disparities in energy deliverability and hampering economic growth in the "have-not" regions.

The Town of Marathon supports the initiative of the Northwestern Ontario Municipal Association, Northwestern Associated Chambers of Commerce, and Common Voice Northwest to apply and pursue Intervenor status in the Ontario Energy Board Consultation on Costs Recovery for Expansion of Natural Gas Services – EB – 2016-0004. Having access to reliable, and competitively-priced natural gas in rural and Northern Ontario will help ensure future economic sustainability of communities and greater economic independence.

Sincerely,

THE TOWN OF MARATHON


Rick Dumas
Mayor

cc: Town of Marathon Council

RD:DS:sg

M:\3-75 (Council)\Correspondence\Mayor\2016\let_0302.David Canfield.doc



respect. works here.